CALIFORNIA ENERGY COMMISSION

UPGRADING CALIFORNIA'S ELECTRIC TRANSMISSION SYSTEM: ISSUES AND ACTIONS FOR 2004 AND BEYOND

DRAFT STAFF WHITE PAPER

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Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Lynn Alexander
Kristy Chew
Judy Grau
Mark Hesters
Don Kondoleon
Clare Laufenberg Gallardo
Susan Lee
Robert Strand
Authors

Robert Strand
Manager
ENGINEERING OFFICE

Sandra Fromm
Assistant Program Manager
INTEGRATED ENERGY POLICY REPORT

Kevin Kennedy
Program Manager
INTEGRATED ENERGY POLICY REPORT

Terrence O'Brien
Deputy Director
SYSTEMS ASSESSMENT AND FACILITIES SITING

Robert L. Therkelsen
Executive Director

Abstract

This staff white paper documents the California Energy Commission's 2004 Integrated Energy Policy Report (IEPR) Committee's and staff's efforts to provide a public forum for evaluating the critical items necessary to achieve a fully collaborative state transmission planning process. The desired process would incorporate state objectives and consider input from publicly owned utilities. The white paper also documents the IEPR Committee's and the Energy Commission staff's efforts to identify and evaluate the actions and strategies necessary to guide the transmission activities in the 2005 IEPR proceeding. The reader can use this white paper, in conjunction with other sources, to help identify needed changes in transmission public policy.

DISCLAIMER

This staff white paper was prepared by California Energy Commission staff. Opinions, conclusions, and findings expressed in this report are those of the authors. This report does not represent the official position of the Energy Commission until adopted at a public meeting.

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The Upgrading California's Electric Transmission System Draft Staff White Paper was prepared with contribution from the following Energy Commission staff:

Renewables Program Staff
Pamela Doughman
Drake Johnson
Todd Lieberg
Melinda Merritt
Ann Peterson
Heather Raitt

Editing/Publication
Evelyn Johnson
Wilma Lee
Mignon Marks
Elizabeth Parkhurst

Cartography
Jacque Gilbreath
Terry Rose

Technical Assistance Contractor for the White Paper (Contract no. 700-02-004)

Lynn Alexander, LMA Consulting
Susan Lee, Aspen Environmental Group

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EXECUTIVE SUMMARY

This white paper is part of the California Energy Commission's 2004 update to the *2003 Integrated Energy Policy Report* (IEPR), building upon the report's recommendation to implement a fully collaborative state transmission planning process in a timely manner. This collaborative process should include the California Public Utilities Commission (CPUC), California Independent System Operator (CA ISO), investor-owned and public utilities, as well as the various stakeholders. This process will allow California to make transmission investments that best meet the state's interests. This paper covers the issues that the Energy Commission staff believes need to be resolved to achieve these goals.

In California's restructured electricity market, bulk transmission lines have increasingly become a "public good," where ratepayers throughout the state share the costs and benefits of a project. Transmission lines are long-lived, require time to plan and permit, frequently cross multiple jurisdictional boundaries, are often controversial, and to be successful must involve stakeholders and the public early in the process. Yet the planning process is not designed to effectively take into account these variables.

Over the last 30 years, however, transmission projects have provided not only the anticipated economic benefits, but have also provided economic benefits that were unforeseen when the projects were first approved. For example, during the 1970s oil embargo, the interstate transmission system saved California over $100 million a month by allowing generators to shut down in-state oil-fired plants and import power from out-of-state, non-oil-fired power plants. These types of strategic benefits, both quantifiable and qualitative, must be captured when a project is evaluated, so that decision makers can make more informed decisions regarding the actual value of a project.

A long-term transmission planning process should be the mechanism to ensure that project evaluations consider these benefits. Other key elements in the process involve corridor planning far enough in advance, so that corridors are set aside and available when needed. Adequate corridor planning helps prevent costly permitting delays, ensures that the optimal routes are used to lessen environmental impacts, and factors in possible alternatives to meet the reliability or economic goals of the transmission project.

2004 Update on Transmission Issues and Actions

This draft staff white paper discusses several key issues and the next steps necessary to continue implementing a fully collaborative state transmission planning process: capturing the strategic benefits, planning for corridors, and adequately assessing the alternatives to a transmission project. In addition, this paper summarizes the status of high-priority transmission projects currently under review.

Capturing the strategic benefits of a transmission line project can help provide the state with the following:

- the insurance against contingencies during abnormal system conditions;
- price stability,
- the mitigation of market power,
- an increase in the sharing of reserve resources,
- environmental benefits,
- a reduction in infrastructure needs, and
- the achievement of state policy objectives.

The staff recommends that additional evaluation of appropriate methods and mechanisms to adequately capture these strategic benefits be conducted in the 2005 Integrated Energy Policy Report process.

The staff also believes that use of a social discount rate, as opposed to an opportunity cost of capital discount rate, is an essential step in recognizing the "public goods" aspects of transmission, as well as their long useful lives (30 to 50 years).

The staff is making recommendations on long-term coordinated transmission planning to engage all stakeholders and the public in a coordinated electricity infrastructure assessment. Implementing these recommendations should create a process that brings forward transmission investments that effectively and efficiently meet the state's long-term needs.

Transmission corridor planning and development is another essential component of ensuring that California's long-term transmission needs are met. Without land available for transmission facilities, new facilities cannot be built, which jeopardizes California's ability to access less expensive energy and renewable resources to meet the Renewables Portfolio Standard (RPS), and meet the reliability needs of the electrical system. Corridor planning and development will also help California meet its goals of increasing its fuel diversity and reducing its dependence on fossil fuels.

Historically, though, California has not planned for the location of transmission facilities on a statewide basis. That task has been left to the investor-owned and publicly-owned utilities, and local land use agencies. Since restructuring, the CA ISO has been responsible for conducting a transmission planning process, along with the investor-owned utilities, for the CA ISO-controlled transmission system. California's growing population, electricity demand, and competition for land make it prudent to plan on a statewide basis for the long-term placement of bulk transmission facilities.

For this staff draft white paper, the Energy Commission brought together stakeholders to further the collaborative planning process initiated in 2003. Through the 2004 Energy Report Update process, these parties and the staff have begun identifying impediments to corridor planning and ways to better plan additional transmission corridors in the state. In this white paper, the Energy Commission staff recommends next steps to further the goal of comprehensive planning of transmission corridors.

Another element of this collaborative planning process should be evaluating non-transmission alternatives early in the process. This element will provide all parties with the greatest number of options and the most complete information in a timely manner. Yet to date, alternatives have not been considered early in the planning process. The consideration of alternatives has been delayed until the permitting process, even though regulatory authorities, industry, and the public agree that waiting until the permitting process is, typically, too late. To be effective, non-transmission alternatives need to be evaluated in the planning process with the same degree of scrutiny as the transmission option. If all affected stakeholders participated in this process, then the best transmission or transmission alternatives would likely move forward to the permitting process.

Several alternatives to transmission lines are available, such as central and distributed generation, and demand-side management strategies that have the potential to fully or partial offset, delay, or displace a proposed transmission project. Non-transmission alternatives can also be used as part of a portfolio approach which looks at a mix of transmission and non-transmission options for meeting the project objectives. This approach could reduce the size of a proposed transmission project, which could result in a net reduction in environmental impacts.

Along with efforts to implement a long-term planning process, the Energy Commission continues to monitor several proposed projects that are needed to ensure reliability, for economic reasons, and/or to bring more renewable energy resources on line. Although the projects meet these short-term goals, the projects could also provide long-term strategic benefits not quantified to date.

The transmission projects under review for reliability will help California meet national, regional, and statewide reliability standards, particularly in San Francisco and the Greater Bay Area. In this area, the PG&E Jefferson-Martin project is needed by 2007 to maintain and enhance system reliability. Upon completion of this project (currently expected to be on line in December 2005) plus other local grid reinforcements, San Francisco may be able to decrease its reliance on old fossil-fueled power plants.

Transmission projects built for economic reasons primarily relieve congestion and reduce the cost of electricity for ratepayers. All high-priority economic projects are located in or serve the southern portion of the state. If these projects are built, Southern California will be able to access greater power supplies from Northern California, Arizona, or Mexico. In particular, the SDG&E Mission-Miguel #2 transmission line was recently approved by the CPUC, and is expected to be operational by June 2006. This project alone will save ratepayers approximately $3 to $4 million per month in congestion costs.

Transmission projects under review will play a critical role in bringing renewable energy resources, typically remotely located, into high-demand areas. The projects are especially needed for the state to meet the goals of its RPS. Without transmission upgrades, those projects in the Tehachapi Wind Resource Area and Salton Sea Geothermal Resource Area compete for limited, or in some cases, the transmission lines are non-existent making these renewable resources inaccessible.

In the 2004 IEPR workshop proceedings, the staff and stakeholders identified the need for a carefully planned approach to interconnect renewable resources to the grid and avoid a more expensive, piecemeal system. A stakeholder group has been formed to identify the initial transmission upgrades needed in the Tehachapi area in addition to a long term plan for the staged interconnection of up to 4,000 MW of additional renewable energy resources.

Next Steps

The staff has prepared this draft white paper to further public discussion regarding the critical issues and actions associated with upgrading California's transmission system. The Energy Commission's IEPR Committee expects to hold workshops this summer to request additional information and input from stakeholders and the general public about the key policy issues in this white paper, which will be used to inform Committee recommendations for the *2004 Energy Report Update* and the *2005 Energy Report*.

CHAPTER 1: INTRODUCTION

Background

This staff white paper, *Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond*, furthers the California Energy Commission's (Energy Commission's) efforts to implement a fully collaborative state transmission planning process that includes the California Public Utilities Commission (CPUC), the California Independent System Operator (CA ISO), investor-owned utilities (IOUs), municipal utilities, and other stakeholders, as recommended in the *2003 Integrated Energy Policy Report (2003 Energy Report)*. The *2003 Energy Report* provides a roadmap for the Energy Commission's 2004 Integrated Energy Policy Report Update (2004 Energy Report Update) work[1], stressing the need to continue implementing a fully collaborative state transmission planning process.

As noted in the *2003 Energy Report*, California's electric transmission system links power generation sources with customer loads in a complex electrical network that must balance supply and demand on a moment-by-moment basis while reliably delivering the lowest-cost power to consumers. The system must deliver these services in a manner that maximizes their value while minimizing negative environmental and other impacts as the system is upgraded to respond to changes in generation and load patterns, including the state's commitment to develop renewable generation aggressively through the state Renewables Portfolio Standard (RPS) program.

The state's existing transmission planning processes have not provided effective and timely mechanisms for bringing forward transmission projects that could provide California with a more robust and optimized system (from a cost, reliability, and environmental impact perspective). These processes include the CA ISO process, which is responsible for the 75-80 percent of California's transmission grid owned by the three IOUs) The guidance of the *2003 Energy Report* served as the starting point for this report, *Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond*.

This paper documents the Integrated Energy Policy Report (IEPR) Committee's and staff's efforts to provide a forum for the public evaluation of the critical items necessary to achieve a fully collaborative state transmission planning process that incorporates state objectives and considers municipal utility input. The white paper also documents the IEPR Committee's and the Energy Commission staff's efforts to identify and evaluate the actions and strategies necessary to guide the transmission activities in the 2005 IEPR proceeding. The reader can use this white paper, in conjunction with other sources, to help identify needed changes in state transmission policy.

Scope of the Staff White Paper

This staff white paper focuses on how to incorporate into the planning process the numerous strategic values currently not assessed in determining the costs and benefits of proposed transmission projects.

Transmission planning was the subject of the first of four transmission-related 2004 IEPR Committee workshops of the 2004 IEPR process, held in November 2003. The November 2003 IEPR Committee workshop highlighted the fact that California's investments in its transmission grid and interconnections to neighboring states have produced substantial reliability, economic, environmental, and fuel diversity benefits. In many cases, California's ratepayers have received significantly greater savings than was projected when the projects were built. The workshop identified the need for an improved methodology for capturing a wider range of benefits than is considered in traditional cost-benefit analyses.

The second IEPR Committee transmission planning workshop, held in April 2004, discussed possible future scenarios of what the transmission system might look like in the year 2030 and the issues that arise as a result. This resulted in stakeholder input on the need for a long-term transmission vision and for a mechanism to ensure that the vision, once established, can be achieved by taking appropriate actions in the near-term. The most important near-term action identified by stakeholders is the need to address corridor and right-of-way planning issues so that the state does not foreclose opportunities for strategic transmission projects in the future due to a lack of suitable corridors. At the June 2004 workshop, the importance of developing an effective planning process that considers alternatives to transmission that successfully meets the state's or the project proponent's goals[2] was publicly discussed.

Finally, this white paper discusses corridor planning, alternatives to transmission, and the status of the near-term transmission projects that the Energy Commission tracks on an on-going basis, including the major renewable projects which are being planned to respond to state RPS mandates[3].

Staff White Paper Development Process

Beginning in November 2003, the IEPR Committee held four public workshops (November 2003, April 2004, May 2004, and June 2004) to solicit public input on transmission issues. The Energy Commission staff placed background papers on its website before each workshop.[4] The IEPR Committee actively encouraged public comments before, during, and after each workshop. This approach ensured that critical issues were fully vetted in a public setting.

A draft staff white paper on accelerating renewable energy development is being prepared concurrently with this paper because renewable energy development poses challenges and opportunities for transmission planning.

Following publication of this draft staff white paper, the IEPR Committee will hold a workshop on August 23, 2004 to solicit public input. The IEPR Committee will consider comments received in response to the workshop in preparing its *2004 Energy Report Update* recommendations regarding transmission issues.

Relationship to Other Efforts

A number of other energy planning efforts are currently underway at the Energy Commission and other agencies. As part of the *2004 Energy Report*, the Energy Commission is preparing two additional concurrent white papers. One white paper, entitled *Accelerated Renewable Energy Development*, discusses such issues as the rules in place and the progress toward reaching the statewide goal of 20 percent of California's electricity generated from renewables by the year 2010; the need for accelerated targets after 2010; utility-specific targets beyond 20 percent before 2010; and the status of public dialogue regarding the possible use of unbundled renewable energy certificates. Another white paper, entitled *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements*, provides an assessment of the implications for electric service reliability, environmental impact, and natural gas use from both the unexpected retirement of aging steam boiler generating units in the state, as well as the continued reliance on these units for power and voltage support.

The CPUC opened a proceeding on January 22, 2004 (R. 04-01-026) entitled "Order Instituting Rulemaking (OIR) on Policies and Practices for the Commission's Transmission Assessment Process." The OIR proposes a revision of General Order (GO) 131-D to enable the CPUC to adopt a "universal" economic methodology developed by the CA ISO. Once adopted by the CPUC, the CA ISO could use the methodology to assess proposed economic transmission projects. The CPUC's goal is to require only a confirmation that the CA ISO used the approved methodology in assessing project need, and it could approve projects without further assessment of need in its Certificate of Public Convenience and Necessity process[5].

Key Assumptions and Definitions

The Legislature has for many years recognized the value of the state's transmission system, the importance of avoiding single-purpose lines where possible, and the need for effective coordinated long-term transmission corridor planning. In Senate Bill 2431 (SB 2431, Chapter 1457, Statutes of 1988, Garamendi) the Legislature found and declared that

> …establishing a high-voltage electricity transmission system capable of facilitating bulk power transactions for both firm and nonfirm energy demand, accommodating the development of alternative power supplies within the state, ensuring access to regions outside the state having surplus power available, and reliably and efficiently supplying

> existing and projected load growth, are vital to the future economic and social well-being of California. The Legislature further finds and declares that the construction of new high-voltage transmission lines within new rights-of-way may impose financial hardships and adverse environmental impacts on the state and its residents….

As a result, the Legislature declared that it is in the best interests of the state to accomplish all of the following in a priority order:

1. Encourage the use of existing rights-of-way by upgrading existing transmission facilities where technically and economically justifiable.
2. When construction of new transmission lines is required, encourage expansion of existing right-of-way, when technically and economically feasible.
3. Provide for the creation of new rights-of-way when justified by environmental, technical, or economic reasons as determined by the appropriate licensing agency.
4. Where there is a need to construct additional transmission capacity, seek agreement among all interested utilities on the efficient use of that capacity.

Although these principles were expressed by the Legislature when California's electricity industry was a regulated monopoly, they remain appropriate principles in a competitive electricity industry. They are also consistent with the more recent direction of Senate Bill 1389 (SB 1389, Chapter 568, Statutes of 2002, Bowen) and the *State Energy Action Plan*.

Furthermore, the *State Energy Action Plan*, which was adopted by the Energy Commission, CPUC, and California Power Authority in 2003, notes that "Reliable and reasonably priced electricity and natural gas, as well as increasing electricity from renewable resources, are dependent on a well-maintained and sufficient transmission and distribution system."

The CA ISO is the quasi-governmental agency that is responsible for planning and operating a reliable transmission system for approximately 75-80 percent of California's power grid. Its control area is approximately 124,000 square miles of the transmission systems formerly controlled by the state's three IOUs: Pacific Gas and Electric Company (PG&E) in the northern and central parts of the state, Southern California Edison Company (SCE) in the central and southern parts of the state, and San Diego Gas and Electric Company (SDG&E) in San Diego and southern Orange counties. The CA ISO requires the IOUs to file annual transmission expansion plans. The plans must show how the transmission owners will meet all CA ISO reliability criteria for a minimum planning horizon of five years. Transmission owners are obligated, in coordination with the CA ISO, to determine what types of facilities could be constructed or expanded to meet the CA ISO reliability criteria. The need for an economically-driven transmission upgrade can also be initiated by the transmission owner. If requested by the transmission owner or another party, the CA ISO may determine whether the upgrade will lower system costs compared to not installing the upgrade.

The present planning process relies heavily on annual transmission expansion plans filed by the IOUs and all other participating transmission owners for the portions of the grid that they own. The CA ISO reviews and either approves or makes recommendations regarding the proposed additions. Recommendations that are not accepted go to a dispute resolution process. As part of the planning process, the CA ISO works with regional transmission groups, primarily through the Western Electricity Coordinating Council (WECC), to ensure that expansion projects do not negatively impact the regional grid and transmission owners in other states.

These annual plans are coordinated with neighboring systems and describe proposed facility additions over a minimum five-year planning horizon. Plans identify system concerns and evaluate the technical merits of various potential transmission, generation, and operating alternatives. In conducting their analyses and developing preferred alternatives, the IOUs are required to address the needs identified by the various stakeholders. The various power flow and stability base cases developed for these annual plans are then used by the CA ISO and other stakeholders for integrated review and independent studies.

The goals of the various projects developed through this process and within the individual IOUs' annual expansion plans include one or more of the following: protecting or enhancing system reliability; improving system efficiency; enhancing operating flexibility; reducing or eliminating congestion; and minimizing the need for Reliability Must Run (RMR) contracts. Congestion in energy transmission systems occurs when local demand for energy approaches the limits of the transmission system's ability to supply it. The CA ISO requires certain generators in areas defined as local reliability areas (LRAs) to sign RMR contracts that require these generators to operate their facilities during periods designated by the CA ISO at specific contracted prices. The CA ISO has generally defined a LRA as an area characterized by both insufficient generation to support effective competitive electricity markets within the area and by limited transmission capacity to import electricity from outside the area.

Projects that provide economic benefits such as reduced costs to ratepayers, like reducing congestion and/or eliminating the need for costly RMR contracts, are generally classified as economic projects. Projects that are needed to ensure the stability of the transmission grid in accordance with widely recognized industry standards are generally classified as reliability projects. Recently a third general category of transmission project types has been defined: renewables projects[6]. Renewables projects contribute to meeting the priorities and standards set by the RPS program, which requires a growing percentage of new generation projects to be met with renewable energy resources.

Transmission planners recognize that many transmission projects provide benefits that have not been counted in the calculation of their primary benefits. Such strategic benefits, which are described more fully in Chapter 2, include the following:

- Insurance against contingencies during abnormal system conditions;
- Price stability and mitigation of market power;
- Increased potential for reserve-resource sharing;
- Environmental benefits;
- Reduction in infrastructure needs; and
- Achievement of state policy objectives.

Report Organization

This report is organized into the following chapters:

Chapter 2: Strategic Benefits and Long-Term Transmission Planning

Chapter 3: Transmission Corridor Planning and Development

Chapter 4: Alternatives to Transmission

Chapter 5: Physical System Needs

Endnotes

[1] Public Resources Code section 25302(d) created the 2004 Energy Report Update process:

> Beginning November 1, 2004, and every two years thereafter, the commission shall prepare an energy policy review to update analyses from the integrated energy policy report prepared pursuant to subdivisions (a), (b), and (c), or to raise energy issues that have emerged since the release of the integrated energy policy report.

This staff white paper was prepared to update the analyses presented in the *2003 Energy Report* and its supporting documents, in support of a *2004 Energy Report Update* to be released by November 1, 2004.

[2] Transmission line projects are put forward by the project proponent to provide or address a specific need, such as voltage support, which may be possible to provide through an alternative to transmission.

[3] The *2003 Energy Report* also recommended that the permitting process for all new bulk electricity transmission lines be consolidated within the Energy Commission. The Governor's Office has not yet responded to the recommendations in the *2003 Energy Report*. In the meantime, the California Public Utilities Commission has opened a rulemaking to consider changes to its permitting process for bulk transmission lines. Therefore, this 2004 Energy Report Update focuses on transmission planning rather than permitting issues.

[4] The following consultant reports are available on the Energy Commission's website:

Consortium of Electric Reliability Technology Solutions (CERTS) report *Planning for California's Future Transmission Grid: Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations*, October 2003, Publication No. 700-03-009:

http://www.energy.ca.gov/reports/2003-10-23_700-03-009.PDF

CERTS report *California's Electricity Generation and Transmission Interconnection Needs Under Alternative Scenarios,* March 2004, Publication No. 700-04-003:

http://www.energy.ca.gov/reports/2004-03-24_700-04-003.PDF

CERTS report *Economic Evaluation of Transmission Interconnection in a Restructured Market*, June 2004, Publication No. 700-04-007:

http://www.energy.ca.gov/reports/2004-06-09_700-04-007.PDF

The Aspen Environmental Group report *Comparative Study of Transmission Alternatives*, June 2004, Publication No. 700-04-006:

http://www.energy.ca.gov/reports/2004-06-08_700-04-006.PDF

[5] The CA ISO's methodology for assessing the economic viability of proposed transmission projects responds to Phase 5 of CPUC Investigation no. 00-11-001, entitled *Order Instituting Investigation into Implementation of Assembly Bill 970 Regarding Identification of Electric Transmission and Distribution Constraints, Actions to Resolve those Constraints, and Related Matters affecting the Reliability of Electric Supply.*

[6] In 2002 the Legislature passed Senate Bill 1078 (SB 1078, Chapter 516, Statutes of 2002, Sher), which created the Renewables Portfolio Standard (RPS) program. The RPS program requires IOUs, electric service providers, and community-choice aggregators to increase their sales of electricity from renewable energy by at least one percent per year, achieving 20 percent by 2017 at the latest, within certain cost constraints. SB 1078 also requires publicly-owned electric utilities to implement and enforce a renewables portfolio standard that recognizes the intent of the Legislature to encourage renewable resources.

CHAPTER 2: STRATEGIC BENEFITS AND LONG-TERM TRANSMISSION PLANNING

Introduction

This chapter discusses the long-term strategic benefits of transmission projects and the need to capture these benefits in the planning process. With a long physical and economic life, transmission projects are a critical "public good," whose value has become increasingly apparent in a restructured electricity market. This public good can best be captured using a social discount rate. This chapter also identifies recommendations regarding long-term transmission planning, assessing strategic project benefits, the use of social discount rates[1] in valuing transmission project benefits, and the development of a long-term vision for California's transmission system.

To further this work, the Energy Commission hired the Consortium of Electric Reliability Technology Solutions (CERTS) to study the strategic benefits of transmission. CERTS's study was subsequently released as *Planning for California's Future Transmission Grid: Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations*. In addition, CERTS prepared two other reports:

- *Transmission Interconnection Needs Under Alternative Scenarios* [http://www.energy.ca.gov/reports/2004-03-24_700-04-003.PDF]
- *Economic Evaluation of Transmission Interconnection in a Restructured Market* [http://www.energy.ca.gov/reports/2004-06-09_700-04-007.PDF]

This chapter was prepared using information from the CERTS reports and input from workshop participants. Information used to prepare this chapter can also be found on the Energy Commission's website under the 2004 Integrated Energy Policy Report Update (IEPR) (2004 IEPR Update).

Past and Current Approaches to Evaluating Transmission Projects

Historically, high-voltage transmission projects were planned and constructed to maintain reliability, connect a remote power plant to load centers, or provide access to a region with surplus generation. In California, these projects included 230 kilovolt (kV) lines, such as Southern California Edison's Big Creek hydroelectric projects to Southern California and from Pacific Gas & Electric's hydroelectric projects to load centers. Later, 500 kV and direct current (DC) lines were constructed for connecting large nuclear and coal plants located in other states to serve the loads within California. For example, a DC line was constructed to connect the Intermountain Coal Plant in Utah to Los Angeles and the 500 kV Palo Verde-Devers line was constructed to connect the Palo Verde Nuclear Plant in Arizona to California's transmission system.

Several large transmission lines, mostly between the Pacific Northwest (PNW) and California, were planned and constructed to take advantage of load diversity between California (summer peaking) and the PNW (winter peaking), and resource diversity — hydroelectric systems in the PNW and fossil fuel generation in California and the Desert Southwest (DSW). Surplus economy energy and capacity exchanges were key benefits from these transmission lines. The existing system is shown in Figure 2-1.

Future transmission projects will provide other strategic benefits, including insurance against contingencies, market power mitigation, fuel diversity, environmental benefits, and meeting state policy objectives, such as developing renewable resources and replacing or retiring power plants. These benefits have to be integrated into the economic evaluation of future projects. As an example, the benefit of power imports from the DSW from 1971-1999 is estimated to be approximately $5.7 billion, nearly a five-fold benefit, compared to an investment of $1.3 billion. Similarly, the PNW imports achieved benefits of $7.2 billion for an investment of approximately $1.6 billion[2].

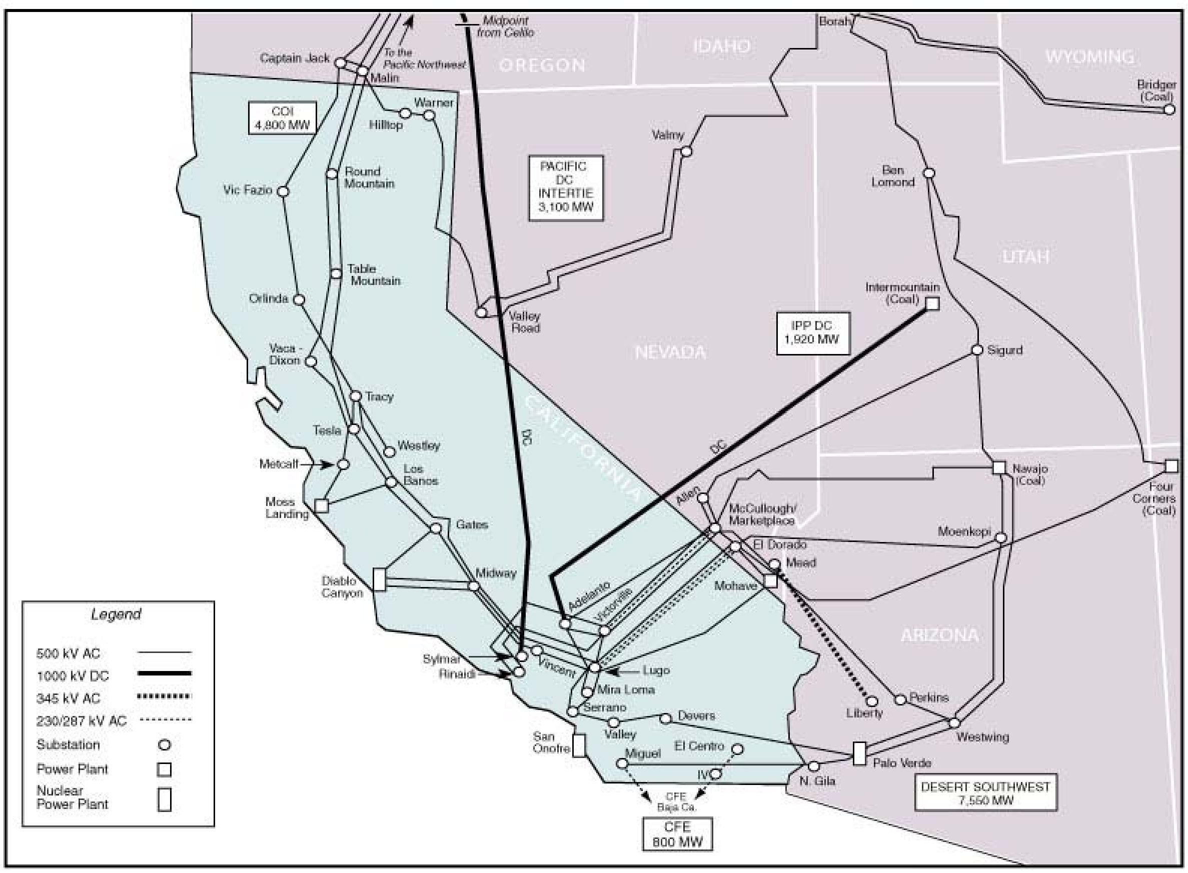
Before the deregulation of the electricity industry in 1996, vertically integrated utilities made planning decisions on both generation and transmission projects. The utilities shared information about their generation plants and forecasts of power plant additions planned to meet their future loads. The utility would set a reliability objective and then select a combination of generation and transmission projects to achieve the reliability objective with minimum revenue requirement. Under a vertically integrated utility structure, integrated planning of generation and transmission was feasible. It was possible to develop a comprehensive multi-regional computer model and data base. Through production simulation, one could determine how much surplus or deficit of power each region would have and what the regional marginal prices would be in determining transmission and generation investments.

Under the restructured electricity market, however, the integration between generation and transmission planning has changed considerably. Currently, planning and decision-making for generation and transmission are "unbundled." Different organizations and market participants are making separate decisions for generation and transmission expansion projects.

As a consequence, the location of new generation is creating transmission congestion. As the cost of congestion goes up, the expansion of transmission lines becomes economically justified. However the price of power and the profit opportunities for generators are also affected by the expansion of transmission. Market interactions are becoming increasingly complex and the marginal prices calculated in a traditional multi-area production simulation computer model are no longer sufficient to forecast the benefit of building a new transmission line. Actual market prices may be much higher or lower than the marginal prices produced by simulation models as prices include more than just variable costs[3]. The bidding strategies of power suppliers have a significant impact on prices and price volatility; power suppliers now have incentives to withdraw capacity from the energy market to increase generator profits.

It is vital that the benefits of transmission projects are accurately captured and are fully represented in the analyses that determine which transmission investments best meet California's needs. The California Manufacturers and Technology Association (CMTA), in commenting on the benefits of transmission to industrial customers at the November 6, 2003 Integrated Energy Policy Report (IEPR) Committee workshop, stated that it is essential for the state to have more infrastructure to mitigate market power and reduce the delivered cost of electricity to ratepayers. CMTA indicated that cost and reliability are the two most important issues to industrial customers.

Figure 2-1
California's Current Transmission Interconnections



Strategic Benefits of Transmission

Transmission planners recognize the strategic benefits of projects. However, because of difficulties in measuring and monetizing them, some of these benefits have not been calculated as part of the economic evaluation of proposed transmission expansion projects. In the future, the strategic benefits of transmission projects must be fully included when evaluating proposed projects, so that decision makers are able to weigh these benefits correctly. The staff recommends that methods to quantify and consider the value of strategic benefits be further assessed during the 2005 IEPR proceedings. These strategic benefits include:

- Insurance against contingencies during abnormal system conditions,
- Price stability and mitigation of market power,
- The potential for increased reserve resource sharing,
- Environmental benefits,
- Reduction in infrastructure needs, and
- Achievement of State policy objectives.

Insurance Against Contingencies

Although the majority of benefits from transmission investments in both intra- and inter-state transmission facilities accrue over a long period of time, significant benefits can accrue over a relatively brief time such as six to 12 months as a result of abnormal system conditions and contingencies that were generally not captured in the planning process. During these abnormal events, the net benefits of a project often tend to completely offset bulk transmission investment costs. These benefits can be in the form of greatly reduced energy costs or substantially improved reliability.[4]

Over the last 30 years, transmission was available during abnormal system conditions that provided critical economic and reliability benefits to California's ratepayers, such as increases in import capacity for reliability, reserve sharing to enhance reliability, economy energy and hydro purchases, and fuel diversity. During the 1970s oil embargo, California saved more than $100 million per month through shutting down in-state oil-fired plants and importing power from out-of–state, non-oil-fired plants. In 1985, power imports offset the loss of 1,200 MW when a reheat steam piping failure kept the Mohave Generating Station off-line for approximately four months. Power imports offset the Palo Verde Nuclear Plant's unplanned outage in the mid-1980s, which was ordered by the Nuclear Regulatory Commission due to steam generator issues. The plant outage represented a loss of approximately 3,600 MW in generating capacity to the DSW area and California (1,000 MW to California). Above–average, attractively priced imports from the PNW during wet weather periods have resulted in substantial energy cost savings. California saved over $900 million in 1984 alone, which was more than the total investment in the Pacific Intertie up until that year[5]. The evaluation processes for proposed transmission projects should include analysis for low-probability high-risk events such as these. The benefits resulting from a proposed project during these events should be considered in addition to the other benefits derived from the proposed project. In the future, transmission project evaluations should include an analysis of these low-probability, high-risk events along with the other benefits from a proposed project.

Stabilizing Prices and Mitigating Market Power

Price stability and mitigating local market power in the restructured electricity market is a critical issue for the state. A new transmission project which reduces congestion in a region has a positive effect on reducing market power opportunities. Congestion on the system has become a more frequent occurrence since the mid-1990s as inadequate expansion of the transmission grid and congestion problems on the state's transmission system exacerbated supply shortages and high prices during the 2000-2001 energy crisis. In other words, increasing transmission capacity may solve local market power problems since the number of suppliers would expand and existing local suppliers would have less incentive or ability to exercise local market power. A new transmission project which reduces congestion may have a positive effect on price stability and mitigation of market power, and this type of strategic benefit should be included in the economic evaluation and permitting decision for a new transmission project.

Reserve Resource Sharing

Another strategic benefit of expanding the transmission network is the potential for increased reserve sharing and firm capacity purchases. If the transmission network were to expand, then fewer power plants would need to be constructed in the importing region to meet reserve adequacy requirements. Importing surplus energy in neighboring regions is possible because of transmission/interconnection system upgrades. In addition to increasing accessibility to the energy supply from other regions, expanding the interconnected transmission network would improve overall system reliability.

Environmental Benefits

The existing transmission system has provided, and continues to provide, environmental benefits for both California and the PNW. When both regions exchange energy, California receives energy from the PNW during peak hours in the summer season, thereby reducing the amount of energy produced from older, less efficient California fossil fuel plants. The PNW receives energy from California, produced during California's off-peak times and in winter months, from newer plants with better efficiency and lower nitrogen oxide (NO_x) emissions, as well as when the ambient NO_x level is lower in California. California's exported electricity is essential for the PNW to meet winter peak demand for reliability purposes. These environmental energy exchanges also help the PNW meet increased in-stream flow releases to mitigate impacts to salmon and other species of fish. NO_x production in

California had been reduced due to a large amount of firm and economy energy purchasers from the PNW and DSW.

Infrastructure Benefits

When an inter-regional transmission line in California is constructed, the level of power production needed in the importing region to meet load generally decreases. This may reduce new generation in the importing region. In California, this may reduce the development of gas-fired generation, with the possibility that additional gas pipelines and pumping stations will diminish. These secondary benefits may not be significant when only a single generation plant is under review. However, when planning is carried out for the state and several transmission lines are being planned, then these benefits will become larger and should be captured in planning for transmission projects.

Although estimating and capturing the infrastructure benefits of a single project may be difficult, these benefits should be incorporated into state-level planning. The Energy Commission staff should examine these benefits when carrying out generation, transmission, and natural gas planning analyses. The Energy Commission staff would then be able to determine the potential impacts of different levels of transmission development compared to the need to expand various power plant infrastructure, including gas pipelines, water, and waste-water systems.

Achieving State Policy Objectives for Renewables

Upgrading California's transmission system can help the state achieve several policy objectives in renewable energy development and environmental protection. Renewable energy resources tend to be located away from load centers. Thus, expanding the transmission system will be necessary to access these resources, and is a vital consideration in planning renewable resource development and achieving state renewable resource policy objectives.

In addition, other state policy objectives may be facilitated as a result of transmission system expansion. The environmental energy exchanges in the 1990s resulted in both regions receiving significant environmental benefits as a result of the electricity transmission system's transfer capability. In addition, transmission system expansion may help facilitate state policy on improving the environmental performance of California's electricity generation system by increasing supply choices and facilitating the retirement of less efficient generation units in the state.

The Need for Long-Term Coordinated Transmission Planning

California's traditional approach to transmission planning is not adequate for addressing transmission issues because it does not capture strategic benefits; the state needs a longer-term coordinated transmission planning process. [6] Since the late 1980s, California IOUs have been unsuccessful in gaining regulatory approvals to build the following major new transmission expansion projects: the Third Pacific Intertie, Palo Verde-Devers No. 2, Path 15, Path 26, and Valley – Rainbow. These projects were denied for a variety of reasons, including: uncertainty about future benefits and evaluation methodologies that did not recognize the strategic value of transmission, present worth valuation that discounted the long-term benefits of long-lived transmission assets, and use of average conditions in long-term planning studies that discount the substantial insurance benefits of transmission projects. During this same time frame, however, the municipal utilities and federal power marketers have pursued transmission investments that are now delivering substantial benefits to their customers.

Traditional approaches to planning transmission are inadequate. For example, no definitive generation expansion plans extend ten years or more into the future to provide guidance for future transmission projects. Consequently, a strategic approach with a long-term horizon is needed to plan regional interconnections to market hubs and resource-rich areas.

Transmission projects often require an eight- to ten-year lead time. Many of the current interconnections being considered in California were first identified 20 to 30 years ago. Therefore, it is critical to address future transmission projects from a strategic, long-term perspective. A good planning horizon for California's future transmission grid would be to look ahead 25 to 30 years. In that time window, it is reasonable to assume that population, economic activity, and electricity consumption will increase, and many of the currently operating power plants will have been retired.

In view of the long-lived nature of transmission lines and the ever-increasing difficulty of planning and permitting needed transmission projects in a manner that addresses the sometimes competing objectives of system reliability, cost-effectiveness, and minimized public health and environmental impacts, the Energy Commission staff began the process of developing a long-term vision for California in this 2004 IEPR Update process. A long-term vision of the state's transmission system developed in a collaborative manner, can provide the framework for making intelligent choices now with respect to the type, size, location, value, cost, function(s), and operational characteristics of future transmission projects, as well as future transmission corridors and rights-of-way, that bring closer to possibility of achieving the vision. In this manner, California can maximize its ability to plan, permit, construct, and operate its transmission system in a manner that achieves state objectives while also considering impacts to California's citizens, environment, and neighbors.

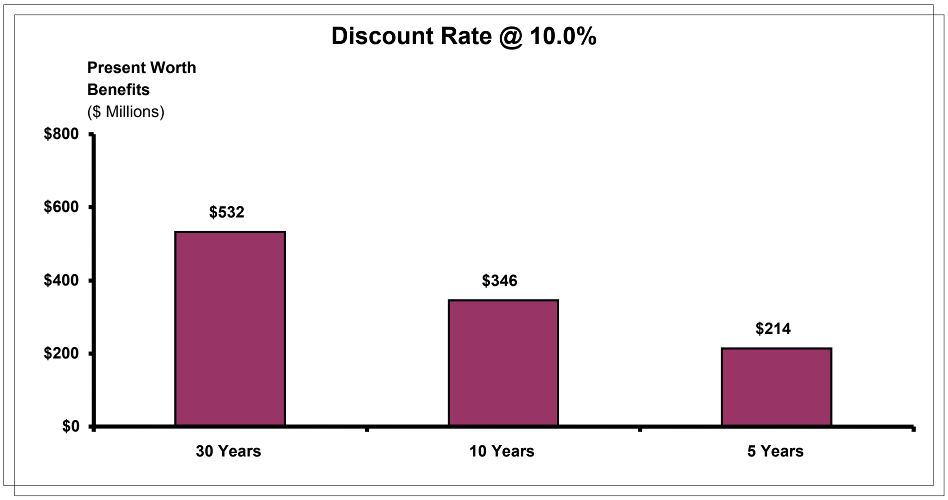
See Appendix A "Development of a Transmission Vision for California" for a summary of the Commission's efforts undertaken in this 2004 IEPR Update process to solicit and consider input from a wide range of stakeholders on the topic of a long-term transmission vision for California. The staff appreciates the input it has received to date from stakeholders on the vision topic. However, given the importance of achieving a vision that represents a consensus view in order to guide future state policy, and the lack of specific input received to date on the draft vision statement, the staff proposes to further address this issue in the 2005 IEPR process.

Long-Term Coordinated Transmission Planning

California needs long-term coordinated transmission planning. The transmission planning process needs to include a two-phase approach: a long-term strategic planning phase and a short-term planning phase. The short-term planning phase should focus on questions and issues which enhance the efficiency and effectiveness of the permitting process for near-term projects, such as close examination of present benefits, alternatives, right-of-way assessments, mitigation of impacts, and multiple agency issues. In the long-term strategic phase, the focus should be on a longer planning horizon, to build consensus on the need for interconnections and to identify potential projects. For interstate projects, this phase would include working with neighboring states to build consensus on projects and corridors as it has become very difficult to obtain siting approval for new transmission paths. Therefore, steps must be taken in the long-term planning process to ensure the utilities can acquire needed rights-of-way. With this approach, the objectives of long-term plans can be achieved and the projects envisioned in these plans can be constructed in time for when they are needed. To facilitate this long-term planning effort, explicit recognition of the time horizon for evaluating project benefits becomes critical.

Figure 2-2 shows an example of the impact of using longer time horizons in evaluating transmission expansion project benefits. For the example 1,500 MW transmission expansion project, using the present worth of benefits at five years for decision-making purposes ignores significant benefits of the project over an assumed 30-year life, and 30 years may even understate the actual useful life of such projects.

Figure 2-2
Impact of Economic Life on the Present Worth of Benefits for a 1500 MW Transmission Expansion Project



Source: CERTS, *Economic Evaluation of Transmission Interconnection in a Restructured Market*, p. 26, June 2004.

Public Comments on Strategic Benefits

During the November 2003 IEPR Committee workshop, one of the Energy Commission's contractors that prepared the *Planning for California's Future Transmission Grid* report explained that many times the benefits of transmission are not realized until five to ten years after the project is constructed. Thus, trying to force a methodology that would require proving benefits in one to four years basically "relegates [California] to never doing anything other than what's needed for reliability as opposed to economic and market efficiency and insurance benefits." [7]

Van Horn Consulting encouraged the Energy Commission to continue developing "a structured, more transparent" strategic process for long-term transmission planning. They expressed their belief that the Energy Commission, in the 2004 Energy Report Update should focus on how long-term transmission planning, particularly how it is influenced by "shorter-term transmission development, such as siting and approval processes." Long-term planning can also provide rationale for shorter-term projects and identify objectives such as "the acquisition or utilization of specific transmission corridors and measures of progress toward fuel and resource diversity goals."[8]

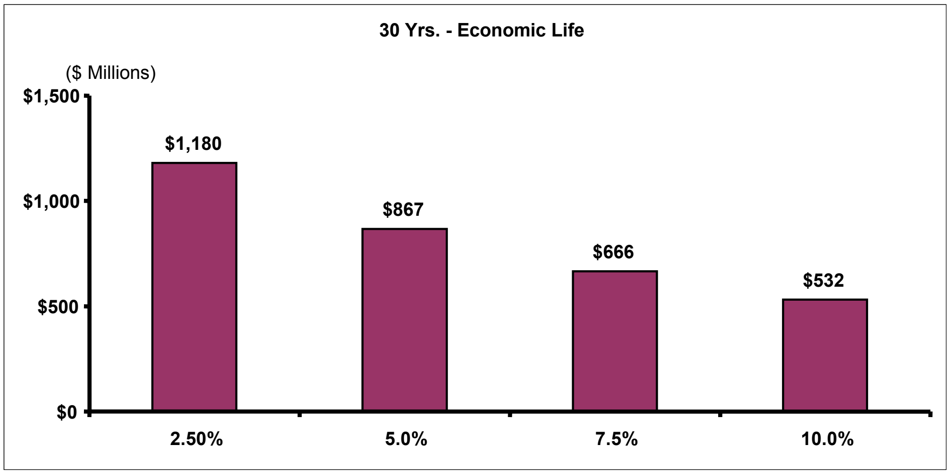
Capturing Strategic Benefits with a Social Rate of Discount

High voltage transmission infrastructure in a restructured market has increasingly become a "public good." The strategic and other benefits from a project cannot be denied to any retail customer or generation owner. The cost is shared by every customer. In California's present restructured electricity market, the planning activity is shared between the utility and the CA ISO, and is subject to stakeholders' input. The utility does not control the operation of the high voltage transmission lines. The utility's customers do not receive all the benefits of a transmission line constructed by the utility. Furthermore, the capital cost of the new high-voltage transmission project is paid through the Transmission Access Charge by all retail customers in the CA ISO grid, as they all receive benefits from the project.

Because the process does not capture strategic benefits of transmission, California should seek other methods to evaluate the economic value of transmission projects. The Energy Commission staff believes using the social discount rate is an appropriate approach. The important question is whether we should continue to use the opportunity cost of capital rate of return (specified by the California Public Utilities Commission for a transmission owner) as the discount rate in the restructured wholesale market. This question is relevant when applying the "societal test" for evaluating a new transmission project which provides strategic and other benefits to ratepayers, as well as generation and transmission owners in both the importing and exporting regions. The question of the social rate of discount has been discussed among economists for decades and many have recommended the use of social discount rates for economic appraisal of public projects in sectors such as transportation, agriculture, water resource development, and land-use. Consistent with this view, the staff believes that state decision makers should apply the "social rate of discount" when using the "societal test" to make a decision on the economic value of a project.[9]

Figure 2-3 shows the implications and importance of using an appropriate discount rate. The project example is 1,500 MW of increased transmission with the same loading and regional price differential used in Figure 2-2. The assumptions used for both Figures 2-2 and 2-3 are shown in Table 2-1. A typical opportunity cost of capital discount rate is 10 percent while a typical social discount rate is 5 percent. The present worth of benefits for the example 1500 MW transmission expansion project is increased from $532 million at a 10 percent discount rate to $1.180 billion at a 2.5 percent discount rate, more than doubling the benefit. As shown by the example, the doubling of the project benefits using the social rate of discount would increase the likelihood that the project would be viewed by decision makers as beneficial to the public.

Figure 2-3
Impact of Discount Rate on Present Worth Benefits for a 1500 MW Transmission Expansion Project



Source: CERTS, *Economic Evaluation of Transmission Interconnection in a Restructured Market*, p. 27, June 2004.

Table 2-1
Assumptions Used for Figures 2-2 and 2-3

Time Period	Line Loading	Annual Energy Transmitted (MWh)	Avg. $/MWh Price Differential (between import and export region)	Annual Benefit ($000s)
On-Peak	80%	5,894,400	$8.00	$47,155
Off-Peak	40%	2,308,800	$4.00	$9,235
Annual Total	62%	8,203,200	-	$56,390

Source: CERTS, *Economic Evaluation of Transmission Interconnection in a Restructured Market*, p. 26, June 2004.

The CA ISO Transmission Evaluation Assessment Methodology with appropriate modifications may be the type of tool to evaluate the economics of a specific project during the short-term planning phase.[10] During the shorter-term planning phase the focus is on a specific project needed in the next ten-year window. For evaluating the costs and benefits of a project, both strategic and economic benefits will be assessed to justify the project. But this methodology would not be appropriate for evaluating strategic benefits or useful in the strategic phase because such a detailed analysis is not necessary or appropriate for building consensus on interconnection needs and identifying potential projects or to conduct corridor planning in the long-term strategic phase.

For the long-term assessment of planning phase, CERTS believes that it is sufficient to assess resource potential and market hubs.[11] Estimates of construction and operation costs in each market hub would be used to establish the price differential for power between different market hubs and, based on historical experiences, an estimate of line loading could also be made. Table 2-2 illustrates the benefit from 1 MW of transmission over a 30-year period when the average benefits (price differential plus strategic value) are $4.00, $6.00, or $8.00 per megawatt-hour (MWh) and the annual loading is 50 percent, 60 percent, or 70 percent. Four interest rates are used: 2.5 percent, 5.0 percent, 7.5 percent, and 10.0 percent. The maximum present value benefit of 1 MW is over $1 million when using a discount rate of 2.5 percent. In this example, the average benefit is assumed to be $8.00/MWh, and the line-loading is estimated at 70 percent.

Table 2-2
Present Worth of 1 MW Increase in Transmission Capacity

	Average Benefit ($/MWh)								
	$4.00			$6.00			$8.00		
	Average Annual Line Loading (%)								
	50%	60%	70%	50%	60%	70%	50%	60%	70%
Discount Rate	Present Worth of Benefits – 30 Year Period ($000s)								
2.50%	$370	$440	$510	$550	$660	$770	$730	$880	$1,030
5.00%	$270	$320	$380	$400	$480	$570	$540	$650	$750
7.50%	$210	$250	$290	$310	$370	$430	$410	$500	$580
10.00%	$170	$200	$230	$250	$300	$350	$330	$400	$460

Source: CERTS, *Economic Evaluation of Transmission Interconnection in a Restructured Market*, p. 32, June 2004.

A refinement of this simple approach would be to use probabilities for each level of benefits and loadings to come up with a probability distribution and expected benefits. A simple decision analysis based on regional electricity prices and the loadings of new transmission lines could provide sufficient information to justify of right-of-way purchases identified through a long-term corridor planning process.

Recommendations of Stakeholders

Stakeholders made several recommendations about the transmission planning during the 2004 workshop process.

On improving transmission planning in California, the California Manufacturers and Technology Association thought that more groups, in particular business groups, needed to work together and focus on long-term energy needs and strategies. [12] The League of Women Voters (League) advocated for a planning process that considers both "economic and environmental justice, as well as technical excellence and costs." The League also stated that the full social and environmental costs of energy production needs to be acknowledged and addressed in the planning process. Lastly, the League encouraged the state to take a leadership role in engaging the decision-making process. [13]

On improving communication, the Electricity Innovation Institute expressed that transmission planners and energy developers needed to work together as partners and not as adversaries[14] while the California Manufacturers and Technology Association expressed the need for better "cooperation and communication between the environmental agencies and the energy planning agencies." [15]

The Electricity Innovation Institute also emphasized the importance of including "advanced technologies and research and development" stakeholders in transmission planning because they are critical to the process too. [16]

Lastly, Sempra Energy Resources thought that energy policies should encourage "third-party non-utility development of transmission." [17]

Recommendations of the Energy Commission Staff

The Energy Commission staff offers recommendations on long-term coordinated transmission planning and the development of a long-term vision, which are vital to engaging all stakeholders and the public in a coordinated electricity infrastructure assessment. The following recommendations on strategic benefits and the use of social discount rates will help provide decision makers with a more complete understanding of the true benefits of transmission expansion.

Long-Term Coordinated Transmission Planning

Beginning in 2005, the IEPR Committee should initiate a biennial examination of strategic long-term interconnection needs and opportunities for California in the *Energy Report*. This approach should include participation by stakeholders including but not limited to, the California investor-owned and municipal utilities, renewable generation developers, and out-of-state power marketers. The examination should be coordinated with the staff's ongoing corridor analysis in the IEPR process to identify the corridors required to facilitate strategic long-term transmission expansion.

Beginning in 2005, the Committee should also initiate an annual examination of the short-term planning projects identified by the CA ISO and other stakeholders. This approach should include participation by stakeholders including, but not limited to, the California investor-owned and municipal utilities, renewable generation developers, other governmental agencies, and interested members of the public. The examination should focus on project benefits, alternatives, right-of-way assessments and mitigation of issues, addressing multiple agency issues, and other issues to facilitate the effective and efficient permitting of near-term projects.

Strategic Benefits and Social Discount Rate

Beginning in 2005, the Energy Commission staff in cooperation with stakeholders should identify and explore various methods for incorporating a social discount rate into the analyses to assess the value of transmission expansion projects in the planning and permitting process. In addition, the staff and stakeholders should identify and explore various methods for quantifying the insurance value provided by transmission expansion projects as a means to avoid contingencies and determine how to incorporate the insurance value in the planning and permitting process.

Long-term Transmission Vision for California

The 2005 IEPR process should take up the development of a transmission vision, using the 2004 IEPR Update work as a starting point. It may be appropriate to integrate the transmission vision into an overall vision that considers all facets of the energy sector. Deferring any immediate decisions on the transmission vision until the 2005 IEPR process will allow the staff to find additional ways to encourage a broader range of stakeholder participation.

Endnotes

[1] The social discount rate is a discount rate used in a net present value calculation when discounting the value of a “public good” benefit of a project. For “public good” benefits, the social discount rate may be used rather than the opportunity cost of capital discount rate.

[2] Consortium of Electric Reliability Technology Solutions. Planning for California’s Future Transmission Grid: Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations. Consultant report. Prepared for the California Energy Commission. Publication number 700-03-009. Appendix, p. 28. October 2003. [http://www.energy.ca.gov/reports/2003-10-23_700-03-009.PDF].

[3] Variable costs are costs or expenses that increase or decrease with increases or decreases in a level of productivity.

[4] The California Independent System Operator (CA ISO), made the following comment at the June 14, 2004 IEPR Committee workshop, regarding benefits of transmission: “There's an inherent value of insurance associated with a little bit more amount of transmission than you require. And that comes about clearly every time I talk to an operator.” (California Energy Commission, Armando Perez, Recorded Transcripts, June 14, 2004 workshop, p. 47:7-15.)

[5] Consortium of Electric Reliability Technology Solutions. Planning for California’s Future Transmission Grid: Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations. Consultant report. Prepared for the California Energy Commission. Publication number 700-03-009. Appendix, p. 28. October 2003. [http://www.energy.ca.gov/reports/2003-10-23_700-03-009.PDF].

[6] The state needs a transmission planning process that extends more than the current CA ISO process of five to ten years. The CA ISO is moving toward a ten-year planning horizon.

[7] California Energy Commission, Vikram Budhraja, Recorded Transcripts, November 6, 2003, p. 53:19-25 – p. 54: 1-4.

[8] Van Horn, Andrew J. and Keith D. White, Van Horn Consulting. Comments on Transmission Assessment and Valuation. June 25, 2004. [http://www.energy.ca.gov/2004_policy_update/documents/2004-06-14-workshop/public_comments/2004-06-25_VanHorn.PDF].

[9] In the Energy Commission’s *Public Interest Energy Strategies Report*, the energy efficiency potential is calculated using a nominal discount rate of 3 percent (California Energy Commission, *Public Interest Energy Strategies Report*. Commission Report. Page 46. Publication number 100-03-012F. December 2003. [http://www.energy.ca.gov/reports/100-03-012F.PDF].

[10] As part of the CERTS white paper entitled Economic Evaluation of Transmission Interconnection in a Restructured Market, CERTS conducted an evaluation of the CA ISO proposed TEAM methodology including background on development of the methodology, status of the methodology and recommendations on use of the methodology. The CERTS evaluation can be accessed on the Energy Commission website.

[11] Consortium of Electric Reliability Technology Solutions. *Economic Evaluation of Transmission Interconnection in a Restructured Market*. Consultant report. Prepared for the California Energy Commission. Publication 700-04-007. June 2004. [http://www.energy.ca.gov/reports/2004-06-09_700-04-007.PDF].

[12] California Energy Commission, Recorded Transcripts, Joe Lyons, November 6, 2003, pg. 138:21-25.

[13] Ibid, Jane Turnbull, p. 107:23:25 – p. 108:1-3 and p. 107:4-13.

[14] Ibid, Ellen Petrill, p. 97:11-17.

[15] Ibid, Joe Lyons, p. 126:13-17.

[16] Ibid, Ellen Petrill, p. 97:20-25 – p. 98:1.

[17] Pak, Alvin S., Director, Regulatory Policy & Analysis, Sempra Energy Global Enterprises. Comments of Sempra Energy Resources. November 17, 2003.

CHAPTER 3: TRANSMISSION CORRIDOR PLANNING AND DEVELOPMENT

Introduction

This chapter summarizes long-term transmission corridor planning issues resulting from the Energy Commission staff's investigation. Corridor availability is vital for transmission system expansion in California. In recent years, several transmission line proceedings have been complex and contentious, such as the Valley-Rainbow and Jefferson-Martin projects, highlighting the difficulty in planning, siting, and obtaining the necessary approvals to construct transmission lines in California.

For the 2004 Integrated Energy Policy Report (IEPR) Update (2004 IEPR Update), the Energy Commission staff collaborated with stakeholders and interested public, to investigate how the Energy Commission should assess the electricity infrastructure and ensure the effective and efficient development of transmission infrastructure projects in California. Many workshop participants of the 2004 Energy Report Update proceeding agreed that transmission development in the state would benefit from better long-term corridor planning and greater public involvement in the planning process.

2004 IEPR Update Process for Investigating Transmission Corridor Planning

The following sections describe the Energy Commission's efforts undertaken in this 2004 IEPR Update to solicit and consider input from a wide range of stakeholders on transmission corridor planning in California.

The Energy Commission staff began its investigation by sending letters to the three investor-owned utilities — Southern California Edison (SCE), Pacific Gas and Electric (PG&E), and San Diego Gas & Electric (SDG&E) — and two publicly-owned utilities: Los Angeles Department of Water and Power (LADWP) and Imperial Irrigation District (IID) in the Southern California region. For this white paper, the Energy Commission staff focused on Southern California for the following reasons:

- The region has the most immediate need for transmission upgrades.
- The region has most of the state's renewable resource potential (e.g., wind resources in the Tehachapi area and geothermal resources in the Salton Sea area).
- Additional imports from Nevada, Arizona, and Mexico could come through the region.
- The region would benefit the most from additional study and corridor planning at this time.

The Energy Commission asked the utilities for: 1) information (environmental, land use, and land ownership data) on each utilities' existing electricity transmission corridors and rights-of-way; 2) any analyses that the utilities have completed that identify major constraints to corridor or right-or-way expansion, such as environmental impacts and mitigation requirements within the utilities' service territory; 3) the utilities' plans for corridor expansion within the study area; and 4) what the utilities believe the study should achieve.

In addition to the letters, the Energy Commission staff presented a concept for preparing a corridor study at the May 10, 2004 IEPR Committee workshop. The staff asked the workshop attendees for input, comments, and recommendations on the proposed study concept and on the next steps for the investigation. To date, LADWP, SDG&E, SCE, and Mammoth Pacific have provided written responses to the letters and the workshop. The Energy Commission encourages PG&E and IID to provide the requested information, comments, and recommendations at their earliest opportunity. The next section is a summary of comments received, followed by the staff responses to each commenter.

Written Comments

In response to the Energy Commission's letter and the 2004 IEPR Update workshops, stakeholders submitted written responses and comments on the proposed transmission corridor study. The written comments are summarized below.

Comments of Los Angeles Department of Water and Power

In its June 2, 2004 letter, LADWP recommended that the Energy Commission's study accomplish the following:

- Identify land corridors that may be reserved for future transmission construction.
- Recommend potential upgrades to existing facilities to increase transfer capability. Consider the following:
    - expected in- and out-of-state resource locations,
    - feasibility of maintaining the corridor for future use,
    - planned utilization of existing facilities,
    - upgrade potential of existing facilities, and
    - considerations for future demand distribution in the state. (Ward, 2004).

Staff Response to Los Angeles Department of Water and Power's Comments and Recommendations

LADWP's comments and recommendations are broad and do not specify a particular area of the state. However, the first recommendation, to identify land corridors for future transmission facilities, will be incorporated into the Energy Commission's corridor study.

Comments of San Diego Gas & Electric

In its June 7, 2004 letter, SDG&E recommended that the "study identify expansion needs to ensure access to the optimum mix of long-term energy resources in California, including renewable resources and energy imports from outside of the state. The study should also outline how this process aligns with the California Independent System Operator (CA ISO) Grid Planning Process and the California Public Utility [sic] Commission (CPUC) licensing requirements."[1]

In a previous letter, dated May 24, 2004, SDG&E provided additional comments regarding corridor planning and state energy policy in response to the May 10, 2004 IEPR Committee workshop on transmission. SDG&E suggested that the policy include a process to designate appropriately sited utility planning corridors across state- and federal-owned land, such as the Anza Borrego Desert State Park and the Cleveland National Forest, to access geothermal energy from the Salton Sea region and the proposed Lake Elsinore Pumped Storage Project. SDG&E also recommended that the Energy Commission and CPUC work together to identify steps needed for the timely, efficient construction of future transmission infrastructure.[2]

Staff Response to San Diego Gas & Electric's Comments and Recommendations

The staff agrees that expanding transmission facilities will be critical to access renewable resources for the state's Renewables Portfolio Standard goals. Additionally, an optimum mix of long-term energy sources is important to the state's energy future. Renewable resource development is a primary reason for focusing this initial corridor study on the Southern California region.

The staff recognizes the need for additional transmission capacity in the San Diego region and that additional transmission facilities through state- and federal-owned land is a possible solution. However, numerous issues are associated with siting transmission facilities within state and federal parks and forests. These issues will require further study and public discussion.

The Energy Commission staff also agrees that the study should describe the context of the study results and recommendations within the other proceedings and processes: such as the CA ISO Grid Planning Process and the CPUC transmission licensing requirements. Currently, though, neither the CA ISO nor the CPUC address corridor planning in these efforts. For more information on these processes, see "Role of the California Independent System Operator" of the Energy Commission's consultant report entitled, *Comparative Study of Transmission Alternatives – Background Report* (Publication Number 700-04-006) which can be found on the Energy Commission’s website at [http://www.energy.ca.gov/reports/2004-06-08_700-04-006.PDF].

Comments of Southern California Edison

SCE provided transmission siting maps and a proposed transmission study plan in their letter dated June 9, 2004.[3]

The objective of their proposed study plan is to identify and adopt transmission corridors for future need, consistent with CPUC General Order 131-D (GO 131-D). Although SCE’s plan would not involve the licensing of specific transmission projects, it would “focus on identifying viable transmission “options” in which (a) project can be constructed, (b) sensitivities can be mitigated, and (c) system reliability can be maintained. Any “viable options [would] be adopted by the [Energy Commission].” SCE proposes the study focus on bulk transmission facilities that are 200 [kilovolts] kV and above because GO 131-D makes provisions for exemptions for construction of new transmission facilities from 50 kV to below 200 kV. SCE suggests that the study would initially focus on the necessary transmission interconnection of renewable generation resources in the Southern California region and could then be applied to other geographic regions in the state.[4]

SCE’s proposes the Energy Commission prepare a corridor assessment consisting of the following steps:

1. Establish and define protocols, rules, and principles for corridor evaluation for assessing the viability of transmission corridor options (e.g., corridors should avoid common contingencies or avoid cultural and environmental sensitivities).

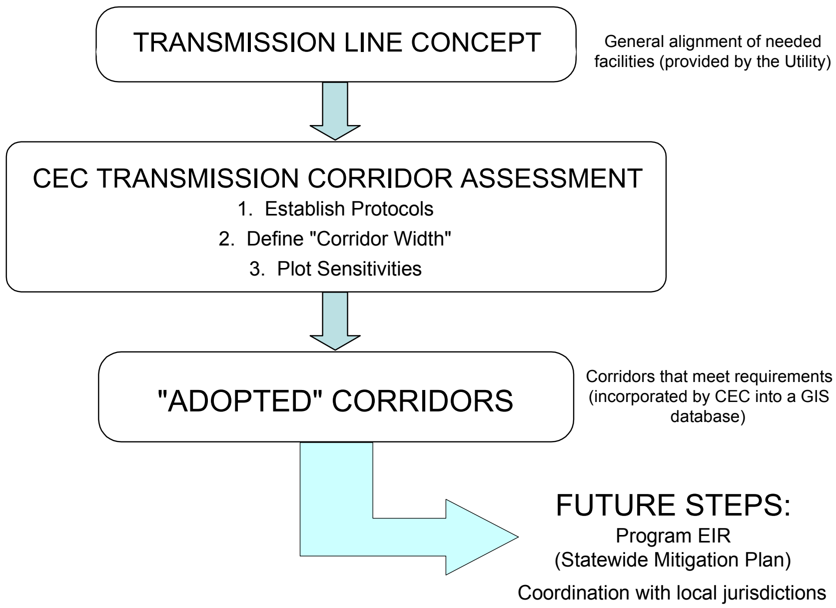
2. Define “corridor width” considering widths that are appropriate for a program environmental impact report <u>and</u> sufficient to prevent creating new reliability problems from common contingencies.

3. Using all available data sources, the Energy Commission would then plot sensitivities in each area of utility-specified transmission need with geographic information system (GIS) technology. Corridors found to be both consistent with the identified need and within the protocols would be adopted.

SCE’s rationale for the study is to “allow the Energy Commission to begin taking the next steps toward fulfilling similar requirements of GO 131-D for the application on transmission facilities above 200 kV.” The next steps include the “initiation of a program environmental impact report (EIR)[5], the development of a statewide mitigation plan, and coordination with local jurisdictions to include the adopted corridors into local general plans.”[6]

Figure 3-1 illustrates SCE’s proposed study plan process.

Figure 3-1
SCE's Proposed Transmission Study Plan Process



Staff Response to SCE's Proposed Transmission Study Plan

The Energy Commission staff appreciates SCE's thoughtful, proposed transmission study plan, and believes several aspects of the proposed plan could result in improved transmission corridor planning in the state. Establishing protocols, defining corridor widths, and plotting sensitivities on a GIS computer platform are all activities that could be undertaken by the Energy Commission staff in the collaborative Energy Report process.

The law, however, currently does not allow the Energy Commission or any other state agency to "adopt" transmission corridors that extend beyond local jurisdictions. Thus SCE's suggestion would need to be investigated to determine the appropriate jurisdiction, the responsible agency, and the process for corridor study and adoption. The Energy Commission is required to assess infrastructure needs in the Energy Report process, and transmission corridors are considered to be a vital part of the transmission infrastructure. Therefore, preferred transmission corridors may be identified in IEPR process. While this identification would not represent state "adoption," this process would recognize and give priority to preferred corridors, which were identified through a collaborative public and stakeholder planning process. As a result of the Energy Commission staff's investigation, which will be presented in the 2005 Energy Report process, the Energy Commission may recommend changes in the law to create the appropriate authority and allow for state adoption of transmission corridors.

If a single agency or combination of agencies adopts transmission corridors, a program EIR that provides a general level of analysis and mitigation measures for bulk transmission lines within the state could streamline later review of project-specific transmission line development projects. Before a program EIR is developed though, the state must determine who the lead agency for the EIR would be and what discretionary action would trigger the requirement for preparing an EIR. If the Energy Commission alone prepared a program EIR on transmission corridors, the CPUC (who currently has regulatory jurisdiction over the permitting of transmission and distribution facilities) could use it. A program EIR could be prepared in coordination with the Energy Commission infrastructure assessment through the *Energy Report* process.

SCE recommends limiting the study transmission line corridors to facilities that are 200 kV and greater because of the provisions of the CPUC's GO 131-D. Because bulk transmission may be 60 kV and greater depending on its function, the staff recommends the study analyze those bulk transmission corridors that could be developed with lines 60 kV and greater.

The staff also agrees that future corridor planning must be coordinated with local, state, and federal land use authorities in the vicinity of future transmission routes. Sharing information and having open discussions with these entities regarding future energy infrastructure needs would benefit energy infrastructure planning. (Chapter 2 of this report describes the staff's vision of a collaborative long-term coordinated transmission planning process that includes corridor planning and assessment in both a long-term and short-term context. SCE's proposed study plan is generally consistent with staff's vision of long term transmission planning.)

Comments of Mammoth Pacific

In its May 21, 2004 letter, Mammoth Pacific indicated concerns with Lines 30 and 31 (115 kV), located between Bishop and Inyokern, California. They stated these lines are a significant impediment to the development of new renewable generation from the Mono-Long Valley Known Geothermal Resource Area (MLVKGRA) of California (Mono County). Its studies indicate that improvements to Path 60 could allow increased generation from 40 MW to greater than 150 MW. Mammoth Pacific recommends that the Energy Commission recognize Path 60 as a priority corridor for attention[7].

Staff Response to Mammoth Pacific's Comments and Recommendations

The Energy Commission staff appreciates Mammoth Pacific's comments and highlighting the transmission needs of the MLVKGRA. Electrical transmission upgrades to support additional MLVKGRA generation have been studied by SCE[8]. SCE's report presents conceptual transmission plans and corresponding transmission cost estimates necessary to accommodate the geothermal resources in the MLVKGRA area. Although the report is conceptual, it identifies a need for additional transmission capacity between the Control Substation in Bishop and Inyokern Substation when additional electrical output of the area exceeds 15 MW[9] (SCE, 2004, p. 6-19).

The staff supports increasing geothermal energy generation and believes this area and other areas in the state would benefit from corridor studies. Therefore, the staff recommends prioritizing such areas in the 2005 IEPR process for future corridor assessments.

Comments During Public Workshops

The subject of corridor planning was discussed during all four 2004 IEPR Update Committee workshops on transmission — November 6, 2003, April 5, May 10, and June 14, 2004. The following sections highlight the comments made during the workshops pertaining to corridor planning and the proposed corridor study.

November 6, 2003 Workshop

The November 6, 2003 IEPR Committee workshop initiated the bulk transmission (greater than 60 kV) planning process for the 2004 IEPR Update proceeding. Workshop participants from a wide-range of backgrounds and perspectives on energy planning shared their thoughts on how to improve energy infrastructure planning and development in California.

Several workshop participants supported the need for more involvement of local communities in transmission infrastructure planning.

- League of Women Voters: The state and local communities need to develop a regional process as a vehicle to bring together the state's "planning concerns and…priorities with local values". [10] To assist in developing the local values, the League felt it would be logical for local communities to include energy planning in their general plans so people are informed of "what's happening in [the] region, and this is what's planned for the electricity system in [the] area."[11]

- Save Southwest Riverside County: This organization's representative emphasized the need for "a complete feedback loop where those who are planning the infrastructure also respect the decisions of the local governments as to where to put those pieces of infrastructure." [12]

SCE also supported long-term transmission planning that includes the coordination and efforts of state and local entities, because "some kind of coordinated plan that allows a transmission project to go 200, 300 miles in order to accomplish its objective…may affect multiple local jurisdictions along the way." The SCE spokesperson further noted that if planning is not coordinated, then it is much more difficult to obtain necessary project approvals. [13]

The California Manufacturers and Technology Association, Save Southwest Riverside, and SCE all emphasized the need for earlier public and local planning participation in the development of transmission corridors. [14] SCE's view was that early public involvement is critical because if the public does not represent its interests then, the project will not result in "a good public interest finding. And that's critical in the permit process in order to be able to successfully do any condemnation that may be necessary in the long run."[15] Save Southwest Riverside reinforced the value of public involvement, that the public has made "really successful efforts…at being constructive, reasonable and… respectful in the process." [16]

SDG&E discussed the difficulty of expanding its transmission system given the number of routing constraints surrounding its service territory (some constraints are Anza Borrego Desert State Park, Cleveland National Forest, and Native American owned land). However, SDG&E hoped that collaborative planning with the state, federal, and local land use agencies could identify a feasible transmission corridor. [17]

April 5, 2004 Workshop

At the April 5, 2004 Committee workshop, the Consortium for Electric Reliability Technology Solutions (CERTS), summarized key findings from its report entitled *California Electricity Generation and Transmission Interconnection Needs Under Alternative Scenarios – Assessment of Resources, Demand, Need for Transmission Interconnections, Policy Issues and Recommendations for Long Term Transmission Planning*. In its presentation, CERTS emphasized that transmission is a very strategic asset and actions should be taken now to secure locations for future transmission facilities. The rationale is that if land is set aside or purchased for transmission before it becomes developed with other uses, then transmission projects can be planned and built in the future when they are needed. Otherwise, areas that are ideal for future transmission routes may be developed for other uses and therefore become extremely difficult to develop with transmission facilities in the future. [18]

Other workshop attendees — SDG&E, Flynn RCI, Southeast Sector Community Development Corporation (SSCDC), [19] Trans-Elect, and, Commissioner James Boyd — supported developing transmission planning of new rights-of-way and the concept of "site banking," "land banking," and "right-of-way banking." Commissioner Boyd reiterated the need for effective land use planning, but noted the difficulties from a historical perspective: when we were first concerned, California had a population of "16 to 20 million," but now California's population is "34 to 35 [million]." So, the site banking concept may be a "last great chance to get ahead of the curve." [20]

The SSCDC also supported the land banking concept. It made the analogy that transmission facility planning and urban development is like a game of tic-tac-toe;

with transmission facilities needing to foresee where the urban development will occur and plan accordingly so that by the time urban development occurs, the land needed for transmission facilities is available and not “blocked” by existing development. If planning were improved, it would “[save] us a lot of trouble and money politically, fighting those battles that don't need to really be fought.” [21]

The SSCDC also stated public education about energy planning needs to improve. In particular, the public needs better information about the environmental impacts of electricity generation and transmission provided in layperson’s terms, “[the public needs information] put to them in a way that [is] not high level, but down to earth where they [the public] can understand it.” [22]

May 10, 2004 Workshop

During the May 10, 2004 workshop, SCE recommended changing existing regulations (i.e., CPUC Decision 87-12-066), “to allow utilities to acquire and hold right-of-way for future use for longer than five years.” SCE further stated that the CPUC’s current “methods for rates limit future use to transmission right-of-way to be no more than five years.” The regulation limits the utility’s ability to only “hold a transmission line right-of-way for a defined project” and not for a future undefined project; it blocks SCE’s “ability to effectively take an adopted corridor and realize an actual right-of-way alignment.” This situation may occur because without cooperative planning in the local area, the local land use agency may issue development permits in the area that would have been ideal for transmission facilities. [23]

The Energy Commission staff reviewed CPUC Decision 87-12-066 and found that in SCE’s 1986 general rate case, decided by the CPUC on December 22, 1987, the CPUC ruled that “...for inclusion in utility rate base of a plant held for future use (PHFU[24])…distribution substations and related transmission plant could be held in PHFU accounts for up to five years….”[25]

SCE also recommended the following actions in its presentation to the Committee:

- Improve the GIS databases that will support the feasibility and impact assessments. [26]
- Develop a program EIR that analyzes adopted corridors. [27]
- Once the environmental impacts are known, work with local jurisdictions to incorporate the corridors into their master planning documents.
- Develop statewide environmental mitigation for transmission development within the corridor. [28]

Also during the May 10, 2004 workshop, the Naval Air Systems Command Weapons Division explained the military’s concerns over tall energy structures, such as wind turbines and overhead transmission facilities in the Tehachapi Wind Resource area.[29] The military has been working with the wind industry on a plan that protects the military’s test and training mission while allowing wind energy projects in the

Tehachapi area and Kern County. Lastly, the military requested that its staff be involved in the planning efforts in the Tehachapi Wind Resource Area, to ensure that the military mission is considered. [30]

June 14, 2004 Workshop

At the June 14, 2004 workshop, Energy Commission staff presented parties' comments on the proposed corridor study received to date. SCE's clarified its written comments and explained that SCE thinks the Energy Commission can make some progress in corridor planning by focusing a corridor study on one renewable resource area like the Tehachapi Wind Resource area and the "southern California region and lines necessary for the interconnection of [that] renewable generation." SCE thinks the study should "explore the meaning of corridor planning" for that region. [31]

Staff Response to Selected Workshop Comments and Recommendations

CPUC Decision 87-12-066 does not indicate that SCE cannot hold property indefinitely for future use, only that property cannot be part of the utility's rate base for more than five years. The Energy Commission staff, in close coordination with the CPUC and the investor-owned utilities, will examine CPUC Decision 87-12-066 further to determine how this decision (and subsequent related decisions) affects meaningful long-term transmission planning.

The Energy Commission staff supports improving, updating, and correcting the GIS databases to support data analysis and impact assessments. The Energy Commission's GIS staff continually updates its GIS databases as available new information is obtained.

The Energy Commission staff's comments on developing a program EIR, statewide mitigation, and coordinating with local jurisdictions on transmission and energy planning are discussed above in response to SCE's proposed study plan.

The Energy Commission staff agrees with SCE's recommendation that the initial corridor study should be focused on a single region within the Southern California area, with an emphasis on accessing renewable energy resources. Regarding the identification of electric transmission constraints and solutions and considering the transmission complexities of the Tehachapi Wind Resource Area, the Energy Commission staff believes that a corridor study of this region could provide substantial information and benefits for the transmission planning and development currently being investigated by the CPUC (CPUC proceeding I.00-11-001).

Recommendations of the Energy Commission Staff

This section summarizes the Energy Commission staff's recommendations and next steps to further the planning and development of transmission facilities in California resulting from the proceeding to date.

The Energy Commission staff recommends that the following corridor planning and development issues be incorporated into the study:

1. For selected projects identified by stakeholders, corridor or right-of-way studies should be included in the 2005 IEPR process.

   The staff recommends working in collaboration with stakeholders to identify projects which need corridor or right-of-way studies to ensure effective and efficient permitting. Stakeholders, interested public, and Energy Commission staff should collaborate on key projects and issues which require resolution. Key projects should include transmission routes in the Tehachapi Wind Resource Area for potential expansion to accommodate the long–term transmission upgrades, identifying potential environmental (i.e., biological resources, land use compatibility, visual resources, and cultural resources) effects of expanding or creating additional right-of-way for transmission facilities in the Tehachapi Wind Resource Area.

   To date, the Energy Commission staff has not received PG&E's or IID's response to the Energy Commission's April 28, 2004 letter. The Energy Commission staff encourages these utilities to provide information, comments, and recommendations for the corridor study at their earliest opportunity. PG&E's input is especially critical because some of the staff's initial corridor study recommendations focus on the Tehachapi Wind Resource Area and proposals to interconnect energy from the Tehachapi region to PG&E's and SCE's systems; the Energy Commission staff must have accurate information about both PG&E's and SCE's systems for the affected region. SCE has provided a substantial amount of information about its system. The Energy Commission staff thanks SCE for its response to the Energy Commission's request for information and appreciates the information shared by SCE.

2. Corridor and right-of-way banking within state- and federal-controlled lands should be investigated in the 2005 IEPR process.

   The staff recognizes the need for additional transmission capacity in the San Diego region and additional transmission facilities through state- and federal-owned land as a possible solution. However, there are numerous issues associated with siting transmission facilities within state and federal parks and forests. These issues require further study and public discussion. Therefore, the Energy Commission staff recommends that, in coordination with the

California Department of Parks and Recreation, U.S. Forest Service, SDG&E, and other appropriate state and federal agencies, the staff research SDG&E's recommendation to develop a process or policy for designating utility corridors across state- and federal-owned land. The findings will be discussed and presented in 2005 IEPR documents and events.

3. What are the effects on long-term transmission planning of limiting the investor-owned utilities' ability to hold property in their rate base to five years?

   The Energy Commission staff recommends an investigation, in close coordination with the CPUC and the investor-owned utilities, of the repercussions of CPUC Decision 87-12-066 and SCE's assertion that it prevents the utility from including property indefinitely in utility rate base. The results of the investigation will be presented in 2005 IEPR documents and events.

4. The concepts of "site/land/right-of-way banking," the "state adoption of corridors," and developing a program EIR – what are they, and how may they help foster better regional and local transmission infrastructure planning and development in California?

   The Energy Commission staff will research the concept of "site/land/right-of-way banking" and SCE's recommendation that the state adopt transmission corridors and develop a program EIR for adopted transmission corridors. Several jurisdictional limitations must be understood before corridors could be "banked" or adopted, or before a program EIR could be prepared. The staff will begin discussions with local planning entities to find ways to improve long-term transmission planning at the local level. The Energy Commission's findings will be presented as part of the 2005 IEPR documents.

5. How should corridor planning be incorporated into the CA ISO's Grid Planning process?

   The Energy Commission staff and the CA ISO acknowledge the importance of coordinating corridor planning with the CA ISO's Grid Planning Process. The Commission staff agrees with comments received from stakeholders that the state should take the lead in corridor planning and should work in collaboration with the CA ISO, other stakeholders, public utilities, and members of the interested public in this effort. The staff will meet with the CA ISO and other participants in the 2005 IEPR process to discuss a process for coordinating these state-led corridor planning efforts with the CA ISO's Grid Planning Process. The results of the investigation will be presented in 2005 IEPR documents.

Endnotes

[1] Orozco, Bernie. San Diego Gas and Electric. Letter to the IEPR Commissioners Geesman and Boyd. Dated June 7, 2004a.

[2] Orozco, Bernie. San Diego Gas and Electric. Letter to IEPR Commissioners regarding Docket No. 03-IEP-01 – 2004 Transmission Update. Dated May 24, 2004b.

[3] Alvarez, Manuel. Southern California Edison. Letter to the California Energy Commissioners Geesman and Boyd. Dated June 9, 2004.

[4] Ibid.

[5] A program EIR is an EIR which may be prepared on a series of actions that can be characterized as one large project and are related either: 1) Geographically, 2) As logical parts in the chain of contemplated actions, 3) In connection with issuance of rules, regulations, plans, or other general criteria to govern the conduct of a continuing program, or 4) As individual activities carried out under the same authorizing statutory or regulatory authority and having generally similar environmental effects which can be mitigated in similar ways.

The program EIR can be used effectively with a decision to carry out a new governmental program or to adopt a new body of regulations in a regulatory program. It enables the agency to examine the overall effects of the proposed course of action and to take steps to avoid unnecessary adverse environmental effects. It also enables the Lead Agency to characterize the overall program as the project being approved at that time.

(Title 14, California Code of Regulations, section 15168.)

6 Ibid.

7 Sullivan, Robert. Facility Manager. Mammoth Pacific L.P. Letter to the California Energy Commission regarding Docket #03-IEP-01 / 2004 Transmission Update. Dated May 21, 2004.

[8] Southern California Edison. *SCE Conceptual Transmission Requirements and Costs for Integrating Renewable Resources*. Prepared for California Public Utilities Commission Decision 04-06-013. July 7, 2004.

[9] The purpose of the SCE's report is to "provide necessary cost information to be used solely for evaluating renewable resource bids so that the most cost-effective bids can be selected on a total cost basis." (SCE, 2004, p. 1-1).

[10] California Energy Commission, Recorded Transcripts, Jane Turnbull, November 6, 2004, p. 143:2 - 6.

[11] Ibid, Jane Bergen, November 6, 2004, p. 144:4-23.

[12] Ibid, Osa Armi, November 6, 2004, p. 141:21-22.

[13] Ibid, Patricia Arons (formerly Patricia Mayfield), November 6, 2004, p. 178:18-25.

[14] Ibid, Joseph Lyons, Osa Armi, Patricia Arons, November 6, 2004, p. 112:1-6 and p. 143:12-24.

[15] Ibid, Patricia Arons (formerly Patricia Mayfield), November 6, 2004, p. 179-1-9.

[16] Ibid, Osa Armi, November 6, 2004, p. 111:8-10.

[17] Ibid, David Korinek, November 6, 2004, p. 164:9-16.

[18] California Energy Commission, Recorded Transcripts, Joe Eto, April 5, 2004, p. 25:14-23.

[19] SSCDC is a California nonprofit corporation with a mission to “defend against environmental injustice as well as promote and cultivate economic development within the Southeastern sector of San Francisco (Bayview Hunters Point, Visitacion Valley and Sunnydale) as a means of eliminating blight, improving health, creating jobs and providing opportunities for small business development by local entrepreneurs.” (http://www.sescdc.com/mpc/docs/Site/index.htm, last modified January 20, 2003).

[20] California Energy Commission, Recorded Transcripts, Commissioner James D. Boyd, April 5, 2004, p. 103:19-25 – p. 104:1-2.

[21] Ibid, Andrew Bozeman, April 5, 2004, p. 78:10-25 – p. 79:1.

[22] Ibid, Andrew Bozeman, April 5, 2004, p. 79:6-9.

[23] California Energy Commission, Recorded Transcripts, Patricia Arons, May 10, 2004, p. 43:14-25 – 44:1-5.

[24] Plant Held for Future Use (PHFU) includes land and plant related items that have been acquired by SCE for use in the future (CPUC, Decision 87-12-66, December 22, 1987).

[25] California Public Utilities Commission, Decision 87-12-066, 26 CPUC 2d, p. 392, 424-425.

[26] California Energy Commission, Recorded Transcripts, Patricia Arons, May 10, 2004, p. 42:18-20.

[27] Ibid, p. 42:22-24.

[28] Ibid, p. 43:7-11.

[29] California Energy Commission, Recorded Transcripts, Anthony Parisi, May 10, 2004, p. 131:10-13.

[30] Ibid, p. 133:1-5 and 19-24.

[31] California Energy Commission, Recorded Transcripts, Patricia Arons, June 14, 2004, p. 229:20-25 – p.230:1-14.

CHAPTER 4: ALTERNATIVES TO TRANSMISSION

Introduction

This chapter investigates how alternatives to transmission projects are currently considered by utilities, transmission planning organizations, and regulatory authorities. To date, alternatives have not been consistently considered in planning and permitting processes in California. This chapter considers ways to efficiently and effectively analyze emerging transmission alternatives, and how, when, and, by whom in the transmission planning process non-transmission alternatives should be considered.

Regulatory authorities, industry, and the public agree that non-transmission alternatives should be thoroughly discussed at the appropriate time in the planning process. This assessment is vital to a collaborative planning outcome that can pass rigorous environmental review during permitting. Numerous stakeholders have argued for this thorough review in proceedings at the Energy Commission and the CPUC. Alternatives include renewable energy, energy efficiency, resource procurement, and ongoing changes to the transmission permitting processes.

Ideally, an alternative to any new transmission proposal needs to simultaneously achieve the goal of maintaining grid reliability without substantial economic costs or environmental impacts. Grid-reliability circumstances, economic costs, and environmental impacts vary case-by-case, which usually means that a range of solutions can be evaluated, leading decision makers to better-informed choices.

Major transmission projects are becoming increasingly difficult to site and permit for several reasons. While California's population growth has increased the need for electricity to be provided to population centers, it has also constrained the land available for construction of major transmission lines. Issues and concerns that arise during transmission line approval proceedings include substantiating the "need" for the line, availability of transmission corridors leading into and through developed areas, visual impacts of transmission lines, potential effects on the value of adjacent properties, electric and magnetic field (EMF) concerns for adjacent land uses, and other environmental effects (e.g., biological, cultural resource impacts) of line installation, operation, and maintenance.

Because of the difficulty in siting and permitting transmission lines, serious study of non-transmission alternatives is becoming more important. The permitting process itself has also been problematic.[1]

- This chapter summarizes stakeholder input and examines potential answers to two key questions: how should non-transmission alternatives (also called non-wires" alternatives) be analyzed and when should these analyses be incorporated into the transmission planning process?

Public Process to Discuss Transmission Alternatives

To encourage public and stakeholder involvement in analyzing transmission alternatives, the Energy Commission published a study on alternatives and held a workshop on the study:

- *Comparative Study of Transmission Alternatives: Background Report* – prepared by Aspen Environmental Group [http://www.energy.ca.gov/reports/2004-06-08_700-04-006.PDF].

- The Energy Commission's Integrated Energy Policy Report (IEPR) Committee held a workshop on June 14, 2004 entitled "Committee Workshop on the 2004 Transmission Update" and devoted the morning session to a discussion of transmission alternatives. (See Appendix B for excerpts from the workshop.)

Potential Alternatives to Transmission Projects

When an inadequacy is identified in the power transmission grid, the problem can often be solved in a variety of ways. Constructing a new transmission line is one alternative; however, strategic placement of new generation facilities or management of the transmission system load could substitute for new transmission lines. While any viable alternative must be able to maintain or support grid reliability, ratepayer costs, economic benefits for other participants (such as developers or utilities), local community goals, and environmental considerations influence the suitability of alternatives.

"Non-wires" alternatives do not involve new bulk transmission lines and are one way to meet load growth. Renewable energy and fossil fuel generation, if it can be produced near the load, is a potential non-wires alternative. In addition, demand-side management (DSM) or conservation, electricity storage, and distributed generation (DG) could reduce the need for a transmission project and thus are also considered as "non-wires" alternatives. Of course, depending on the location of each generation source, these alternatives could also require transmission interconnections.

The following alternatives to transmission lines are briefly described below: new generation, electricity storage, and conservation and DSM.

New Generation

When properly located, generation can reduce or eliminate the need for transmission lines. Generation includes large-scale natural gas, oil, coal, or nuclear power plants, smaller-scale distributed generation, and renewable energy technology installations (e.g., solar, wind, geothermal, biomass, hydro, and tidal power).

Fossil-Fueled Power

California has over 30,000 MW of in-state generation capacity provided by natural gas-fired generating facilities. In 2004, these facilities are expected to provide 36 percent of the electricity within California. These plants are located where there is adequate industrial land and fuel supply, usually a natural gas pipeline. If sufficient power plants were located in or near load centers, bulk transmission lines could be avoided. However, siting plants near load centers and populated areas is difficult because of the potential environmental impacts from these facilities. Air emissions, noise, water use, and visual impacts are generally the greatest concerns during power plant siting cases. New large power plants also require significant financial commitment and lead-times, which further complicate this alternative to a bulk transmission project. Comments from SCE point out that prevailing economic conditions, not transmission system reliability, govern where and when large power plants are developed or retired. SCE noted that merchant power generators can retire or mothball plants depending on their financial situations.[2]

Renewable Energy Options

Renewable energy generation sources can be an alternative to new transmission lines if available near load centers. Away from loads, renewable technologies require transmission lines. For example, large-scale wind or solar-electric systems normally require substantial amounts of land and appropriate site conditions, which can require bulk transmission lines if far from load centers. If wind and solar resource areas are near a load center, only local transmission lines would be necessary to deliver the power. The difficulty of bringing renewable energy to urban load centers is illustrated by comments from SDG&E, that serves a region that most likely will need new bulk transmission line expansions before the utility can meet its RPS targets.[3]

Distributed Generation

Distributed generation is locating small-scale power-producing facilities, in the range of a few kW to a few MW, in and near load centers. Many DG technologies exist, including microturbines, internal combustion engines, combined heat and power (CHP) applications, fuel cells, photovoltaics and other solar energy systems, wind, landfill gas, digester gas, and geothermal power generation technologies. DG technologies that burn fossil fuel must be located where the fuel can be delivered, similar to larger-scale fossil-fueled power plants. Some forms of DG, such as solar-electric or fuel cells, involve comparatively low air emissions, noise, and water use, but fuel cells are presently only available on relatively small scales, up to about 1 MW. DG technologies may be combined with electric storage technologies to allow rapid response to load changes, which can add reliability to the system.

Several economic incentive programs exist for DG systems in California through the Energy Commission and the CPUC. Comments from Communities for a Better Environment (CBE) highlight that DG installations are also economically justifiable because they can be used to improve the stability and reliability of the local electric supply without requiring new expansions of the existing grid.[4] As an added benefit, DG installations may allow new transmission expansions that would otherwise be paid for by ratepayers, to be deferred. The San Francisco Public Utilities Commission (SFPUC) noted that economic incentives for DG should reflect the savings provided by deferring grid expansions.[5]

Summary of Generation Options

Table 4-1 summarizes generation alternatives to transmission and identifies the major constraints associated with each technology. Some generation technologies produce relatively small amounts of electricity, however, they can only defer the need for new transmission lines by a year or two. Many larger renewable generating installations — especially wind, hydroelectric, and geothermal power — have geographic constraints which limit their accessibility and availability. As a result, these generators generally require transmission to transport electricity to areas of demand.

Table 4-1
Summary of Generation Alternatives to Transmission

Technology	MW of individual facilities or fields	Location-Dependent?	Other constraints?
Gas-fired turbines – peakers	50 MW	no	Can be difficult to site in developed areas
Gas-fired turbines – combined cycle	100 – 1000 MW	no	
Fuel cells	up to 1 MW	no	Developing technology
Solar thermal electric	up to 100 MW	yes	Requires large land area & maximum thermal radiation
Solar photovoltaics	250 kW on buildings; up to 6 MW in field	no	Small scale installations at relatively high cost
Wind	Farms 30-40 MW	yes	Geographic siting – requires transmission to get to load
Geothermal	up to 110 MW	yes	Geographic siting – requires transmission to get to load
Hydroelectric	up to 400 MW	yes	Very few new facilities are likely
Tidal	up to 240 MW	yes	New technology not applied in U.S.
Biomass	up to 10 MW or larger	yes	Requires access to fuel

Electricity Storage

Storage technologies can be used to balance fluctuations in the supply and demand of electricity. Although storage cannot replace generation, it can be used in a distributed role by being charged during off-peak periods for electrical use during on-peak periods. Electricity storage units are usually small-scale (under 10 MW for multi-hour operation), and they are normally located near the end user of electricity. This emerging technology will require additional development and commercialization before it can be used widely as an alternative to transmission.

Conservation and Demand-Side Management Options

Reducing electric demand can defer the need for transmission lines for varying periods of time. Broad conservation strategies include energy efficient appliances and public conservation practices during peak conditions, to highly technical

Internet-based technologies that manage peak load. Since 1975, the peak demand displaced by the building and appliance standards has been roughly 5,400 MW[6]. Beyond conservation, the following two components of DSM are alternatives to transmission:

- Load shedding: a controlled interruption of electric supply to customers, usually due to temporary shortage of supply. Load shedding is rare, not normally preferable, and most commonly applied during times of emergency or severe shortage, such as during the California energy crisis in 2001. Voluntary load shedding, through interruptible-rate incentive programs, can be used to avoid outages and defer the need for new generation.

- Load shifting: the practice of altering the pattern of electricity use so that on-peak use is shifted to off-peak periods, a fundamental DSM objective. Incentives to shift load include receiving lower prices of electricity through "time-of-use" rates offered by the electric utilities.

Although conservation is an essential component of electricity system operation, the available electricity savings from other load management programs are generally small and are generally insufficient to be used as a stand-alone alternative to transmission.

Transmission Planning in California

Alternatives to transmission projects can be considered in at least two points in the transmission planning process: during pre-application project planning (involving the utility, the CA ISO, and certain stakeholders) and during permitting of a proposed project under the California Environmental Quality Act (CEQA). Because some transmission system owners do not participate in the CA ISO (e.g., Sacramento Municipal Utility District), the CA ISO does not oversee planning for **all** transmission expansions in California. In addition, because the CPUC has jurisdiction of investor-owned utilities only, no single common procedure exists for planning or permitting new transmission facilities in the state. This lack of coordinated oversight prevents the State from developing a consolidated approach to consider transmission alternatives.

Transmission planning for IOU expansions within the CA ISO grid begins with the IOU Annual Transmission Grid Expansion Plan, which has approximately a ten-year horizon for major projects. This plan allows the participating transmission owners to identify possible expansions or alternative solutions to transmission-related problems although a wide range of stakeholders is not typically engaged. The CA ISO and stakeholders then review the plan, and the CA ISO recommends its preferred solutions in its annual Controlled Grid Study Report. This process is the first point at which alternative means of solving a transmission-related problem can be considered.

The second opportunity for identifying alternatives to transmission expansions occurs when an IOU applies to the CPUC to approve a specific project. During this process, CEQA requires the CPUC to identify and consider alternatives that can minimize the environmental impacts of specific projects. However, non-transmission alternatives are not usually considered during the CPUC process because by the time a project is submitted to the CPUC, the need for additional transmission capacity has usually become so urgent that longer-term or portfolio solutions are not considered feasible. Under CEQA Guidelines, timing alone can eliminate alternatives that require more lead-time to implement.[7] Additionally, no coordinated planning process captures potential transmission projects by non-CA ISO members or publicly-owned utilities that are unregulated by the CPUC.

The CA ISO recognizes that the planning process does not fully consider new generation options or other "non-wires" alternatives to transmission projects. Comments from the CA ISO note that the options of new generation or DSM are unavailable to the CA ISO because that organization has no role in planning those types of programs or facilities.[8] "Non-wires" alternatives could be discussed during the CEQA process (conducted by the CPUC and other agencies), except that lead-time is usually insufficient.

Several stakeholders noted that improving the transmission planning process would incorporate the need for a long-range perspective, without adding to the lead-time of projects, and the ability to quickly implement alternative solutions. Comments from the Independent Energy Producers Association (IEP) indicated that a three-tier system should be in place: 1) a long-term planning process for essential reliability purposes, similar to the ten-year horizon offered by the CA ISO process; 2) a more immediate process for projects that can be implemented quickly within a one- to five-year timeframe; and 3) a process that somehow ensures achieving the fulfillment of the RPS goals.[9] The utilities stressed that "non-wires" alternatives are already either built into their long-term planning[10] or that broader consideration of "non-wires" alternatives could add to the lead-time for implementing transmission projects.[11]

Examples of Alternatives to Transmission

The following examples demonstrate previous efforts to identify non-transmission alternatives.

2001 CA ISO Request for Proposals (RFP) Process for the Tri-Valley Area

The evolving grid planning process at the CA ISO led that organization to issue an RFP in 2000 to identify non-transmission alternatives to a transmission expansion plan proposed by PG&E in the Livermore area. The CA ISO wanted to determine whether otherwise competitive (i.e., cost-effective and reliable) generation would agree to locate in the southern Tri-Valley area and provide peaking capability, and/or whether demand reduction could be encouraged through peak load management programs. At the conclusion in April 2000, the CA ISO found that while four proposals could provide reliable alternatives to the PG&E transmission project, none provided cost-effective alternatives. Therefore, the CA ISO directed PG&E to proceed with its transmission expansion plan as the least-cost solution. This transmission project was later approved by the CPUC in October, 2001.

San Francisco Public Utilities Commission Electricity Resource Plan

This plan was adopted in December 2002 as a policy guide to be used by the City and County of San Francisco in its actions relevant to providing reliable, affordable, and sustainable electricity. It illustrated a preference for improved energy efficiency, expanded use of renewable energy resources, and steps to improve reliability through a combination of carefully prescribed local generation and transmission system improvements.

San Diego Regional Energy Strategy

The San Diego Regional Energy Office provides information, research, analysis, and long-term planning on energy issues for the San Diego region. This organization prepared The San Diego Regional Energy Strategy (Strategy) (May 2003), which was partially adopted the San Diego Association of Governments in July 2003. The Strategy identified "alternative" means of meeting demand through energy efficiency and demand-response programs, distributed generation, and use of renewable resources.

Bonneville Power Administration (BPA) Non-Wires Initiative

The BPA recognizes that alternatives to transmission projects must be evaluated to minimize environmental impacts. To aid the environmental review of transmission system expansions, BPA is using a "non-wires initiative" to expand the planning process to consider non-transmission options. The "non-wires initiative" aims to identify reliable and cost-effective alternatives to transmission expansion early. Because implementing "non-wires" solutions requires a wide range of stakeholders, including other regional utilities, merchant power generators, regulatory commissions, and power customers, specific "non-wires" solutions have only been identified for certain sub-regions. The non-transmission strategy to date has been to shift or reduce the transmission load in specific areas. A "non-wires" pilot program is underway in 2004 for the Olympic Peninsula where BPA will pay certain customers to curtail power purchases during peak hours. Through the program, BPA hopes to achieve about 30 MW of deferred demand and potential generation.[12]

Summary of Stakeholder Input

The stakeholder input illustrates a number of existing challenges that agencies, the public, and utility operators currently face. The following is a brief summary of the June 14, 2004 IEPR Committee workshop:

- Planning efforts coordinated by the CA ISO or the CPUC affect mainly the three major IOUs as the CA ISO cannot guide the actions of non-participating transmission operators, and the CPUC cannot guide the actions of publicly-owned utilities or other transmission operators that are not IOUs. In addition, the CA ISO and the CPUC have limited ability to investigate or dictate when "non-wires" alternatives could be feasible. The CA ISO normally does not solicit proposals for "non-wires" alternatives, and the CPUC permitting process generally does not allow enough lead-time to consider "non-wires" alternatives through CEQA, where the alternatives analysis is guided by the applicant's project objectives.

- Currently, the CA ISO and CPUC have independent processes to identify whether a transmission project is needed. The CA ISO and CPUC are presently working to develop a methodology to evaluate the standard of need through CPUC proceeding R.04-01-026.

- The CA ISO develops solutions for transmission problems during an annual review that involves IOUs, but does not engage local land managers and community officials who reflect the concerns of the affected communities, or potential developers of "non-wires" alternatives. The transmission system can be optimized to increase use and improve access to renewable generation, if tariff and operational changes are implemented by CA ISO. However, work by the Rocky Mountain Area Transmission Study (RMATS) indicates renewable generators have difficulty securing firm transmission service on congested lines.[13]

- The Energy Commission has limited ability to investigate whether proposed generation could be inappropriately located relative to load centers and the existing transmission system. Prevailing economic conditions and decisions by merchant power generators, rather than consideration of transmission system reliability, dictate where and when large power plants are developed or retired.

- Transmission system deficiencies highlight system vulnerabilities that involve sensitive information relative to security concerns, yet the information may need to be shared with a wide range of public stakeholders so that alternatives to system improvements may be discussed fully.

- Distributed generation and DSM may be used to balance loads and improve local reliability, but no mandate requires these systems to be implemented on a broad scale.

Recommendations and Next Steps

This section provides the recommendations of the Energy Commission staff and identifies the next steps that the state should take to allow broader consideration of alternatives to new transmission projects.

Presently, the planning process that occurs between the IOUs and the CA ISO does not effectively engage local interests (especially landowners along the potential transmission corridors) or all potential developers of transmission alternatives. This absence generally results in the CA ISO recommending solutions without considering “non-wires” options in any detail or depth. Engaging wider public participation, especially local interests, would provide a more rigorous consideration of “non-wires” alternatives. A series of well-publicized public meetings could be held in the local project route area and through coordination with local jurisdictions. Non-CA ISO members such as municipal utilities could, if necessary, use a similar approach in their services areas.

The transmission planning process should continually evaluate the availability of alternatives. Absent any other similar existing process, the Energy Commission should work with the CA ISO to explore the feasibility of examining “non-wires” alternatives in the CA ISO’s annual Controlled Grid Study process, which has a ten-year planning horizon. Early consideration is necessary for identifying the alternatives that are the most cost-effective, most likely to satisfy reliability concerns, and most consistent with local and regional goals because of the long lead-time of certain alternatives, like new generation.

The Energy Commission staff recommends the following actions for better consideration of transmission alternatives in the transmission planning process:

1. Discussion of potential new transmission projects should occur in a forum that would successfully and consistently involve potentially affected local communities so major concerns with conceptual transmission improvements could be shared at the earliest possible time.

   The Energy Commission staff recommends establishing, as part of its collaborative planning process, a mechanism that ensures early and well-publicized stakeholder meetings in the project area. Notice should be provided to affected local governments and, if possible, to potentially affected landowners. Non-CA ISO members, such as publicly-owned utilities, should also be engaged in the process.

2. Expand public awareness of transmission problems at an early stage so that generation developers (including developers of renewables, fuel cells, distributed generation, and energy facilities that can be permitted outside of state regulatory processes) and proponents of demand response and other "non-wires" alternatives could present viable alternatives before the need for transmission is so urgent that alternatives become infeasible.

Staff and stakeholders should develop formal methods for informing stakeholders of transmission congestion problems in the 2005 IEPR process.

Endnotes

[1] Utilities and other stakeholders have been critical of permitting delays, insufficient information sharing, or project denials that conflict with CA ISO recommendations.

[2] California Energy Commission, Recorded Transcripts, Patricia Arons, June 14, 2004, p. 127:8-15.

[3] Ibid, Dan Ozenne, June 14, 2004, p. 122:3-11.

[4] Ibid, Greg Karras, June 14, 2004, p.81:7-25.

[5] Ibid, Ed Smeloff, June 14, 2004, p. 75:22-25 – 76:1-5.

[6] Aspen Environmental Group. Comparative Study of Transmission Alternatives - Background Report. Prepared for the California Energy Commission. Consultant report. P. 16. June 2004. [http://www.energy.ca.gov/reports/2004-06-08_700-04-006.PDF].

[7] Title 14, California Code of Regulations, section 15126.6 (c).

[8] California Energy Commission, Recorded Transcripts, Armando Perez, June 14, 2004, p.40:6-10.

[9] Ibid, Steven Kelly, p.105:8-25 – 106 1-19.

[10] Ibid, Dan Ozenne, p.120:8-19.

[11] Ibid, Chifong Thomas, p.113:14-22.

[12] Transmission Business Line: Non-Wires Solutions Update, Bonneville Power Administration, 2003.

[13] California Energy Commission, Recorded Transcripts, David Olsen, June 14, 2004, p.100-101:1-17.

CHAPTER 5: PHYSICAL SYSTEM NEEDS

This chapter focuses on the California Energy Commission (Energy Commission), California Public Utilities Commission (CPUC), California Power Authority, and California Independent System Operator (CA ISO) joint agency "watch list" of transmission projects which are needed to meet three state policy goals: projects to ensure a reliable network, projects for economic reasons, and projects for bringing more renewable energy projects on line. See Figure 5-1 for a state map identifying these projects.

Projects to Ensure a Reliable Network

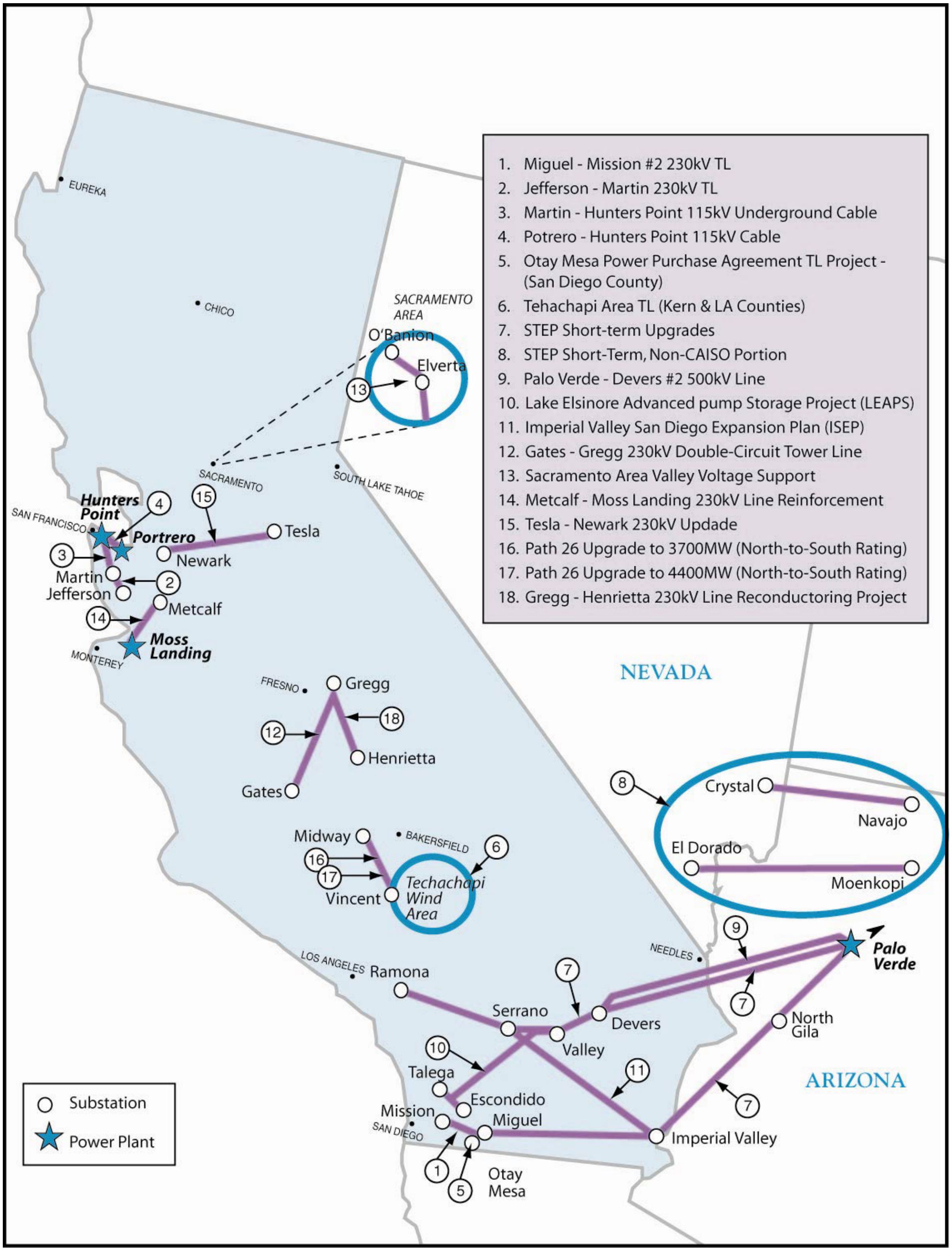
Transmission projects are needed to address reliability issues in Northern California, particularly to address deficiencies in San Francisco and Greater Bay Area. Eight key projects have been identified in Northern California and five of these projects serve the Bay Area. The remaining three projects are located in the Sacramento and Fresno areas. These projects are necessary to ensure that the California grid meets national, regional, and statewide reliability standards.

San Francisco and the Greater Bay Area

Five high-priority projects are located in San Francisco or serve the Greater Bay Area. This region has seen significant load growth without a corresponding increase in transmission infrastructure, which has led to decreasing system reliability, delays in maintenance for critical facilities, and a continued reliance on older power generation facilities.

Three of the high-priority projects directly serve loads in the City and County of San Francisco. These projects, the Jefferson-to-Martin 230 kilovolt (kV) line, and the Potrero-to-Hunters Point 115 kV underground cable, along with a combination of many smaller system upgrades, would allow San Francisco to meet reliability standards beyond 2012.[1] The Hunters Point-to-Martin 115 kV underground cable is not needed until 2011 based on current load forecasts. However, if San Francisco experiences higher than expected load growth the project will be needed sooner.[2] Without these upgrades, PG&E could begin violating reliability standards for the San Francisco Peninsula region starting in 2006.

Figure 5-1
Map of Transmission Projects on the Watch List



The other two Bay Area projects, the Metcalf - Moss Landing 230 kV reinforcement and the Tesla - Newark 230 kV upgrade, are needed to serve growing loads by increasing the transmission network's ability to reliably move power into the Bay Area.[3] The Metcalf - Moss Landing 230 kV reinforcement project would essentially upgrade existing facilities so that they can carry more power between Moss Landing and the south end of San Jose. PG&E is currently working on the permit application for this project. Without the project, the transmission network into San Jose is forecasted to experience reliability criteria violations starting as early as 2007.[4] The Tesla - Newark 230 kV upgrade is not needed until after 2007 and is designed to increase the transmission network's ability to move power from California's 500 kV "backbone" system into the Bay Area and reduce the cost of Reliability Must Run (RMR) contracts, thus saving ratepayers money.[5] Overall, these five projects would significantly improve the reliability of the San Francisco Bay Area transmission network.

Jefferson-Martin 230 kV line[6]

Project Background. The Jefferson - Martin 230 kV line is an approximately 27-mile transmission line that would extend from the Jefferson substation in San Mateo County near San Carlos to the Martin substation in Brisbane. The project that PG&E proposes is a combination of 14.7 miles of overhead line installed on a rebuilt 60 kV double-circuit transmission line (the southern section) and 12.4 miles of new underground duct bank (the northern section). However, numerous alternative routes exist and, as of this writing, the proposed decision by the CPUC Administrative Law Judge, if approved, would underground a large portion of the project, with the only above-ground portion crossing the Crystal Springs Reservoir Dam. Depending on the route chosen, the final project is estimated to cost between $180 million and $244 million.

As of July 2004, the CPUC is scheduled to vote on whether to grant a Certificate of Public Convenience and Necessity (CPCN) for the project on August 8, 2004. The proposed decision (in A.02-09-043) recommends granting the CPCN, although the route may differ from PG&E's proposed route and the costs could change. Assuming approval on August 8, 2004, and assuming the final route decision is not contested in court, the transmission line could be constructed and operating by December 2005.

The proposed decision includes the analysis of alternatives to the project and considers the potential benefits from supply diversification, and impacts on the price of electricity and the environment. The planning process for both the Jefferson-Martin line and the cable projects inside San Francisco began in 1999. The *San Francisco Peninsula Long-Term Electric Transmission Planning Technical Study* submitted to the CA ISO Board of Governors in October 2000 analyzed system reliability with three different load scenarios to test the impact of an economic downturn or a significant (400 MW) combination of distributed generation and conservation. Scenarios that analyzed the impact of the closure of existing power plants and the potential for new power plants were also included. Because of the uncertainty surrounding alternatives to the transmission project, PG&E decided to pursue the Jefferson - Martin 230 kV line. In the CPUC's proposed decision, the project is found to be needed for reliability in 2007, but the strategic, environmental, and economic benefits make the project beneficial in 2005.

Issues and Consequences of Delay. The major issues remaining in the CPCN process are the electric and magnetic field (EMF) concerns expressed by the homeowners living near the proposed route and the request for meaningful consultation by the Golden Gate National Recreation Area (GGNRA). The proposed decision addresses the EMF issue by choosing a route that puts the majority of the project underground. The Superintendent of the GGNRA is asking for meaningful consultation on operations and construction details and mitigation for the "hybrid" route and is threatening to take the issue to court if the consultation is not granted. The GGNRA has jurisdiction over watershed lands south of San Francisco in the area of Crystal Springs Reservoir.

Delays in the construction of this project will result in a gradually increasing reliance on old fossil-fueled plants in San Francisco and a decrease in system reliability. The thin reliability margin in San Francisco will continue to make it difficult to maintain existing facilities and, combined with the increasing demand for electricity, will increase the likelihood of power outages in San Francisco.

Potrero - Hunters Point 115 kV Cable[7] and Hunters Point - Martin 115 kV Cable Projects[8]

Project Background. The Potrero - Hunters Point 115 kV cable is 2.4 miles of underground cable needed to reinforce the San Francisco's internal transmission network that will cost between $11 million and $13 million. The Martin - Hunters Point 115 kV cable is approximately five miles of underground cable that will cost between $35 million and $45 million and will significantly improve the transmission network's ability to serve San Francisco's electricity needs.

PG&E applied to the CPUC for a Permit to Construct (PTC) the Potrero - Hunters Point cable on December 30, 2003. A schedule for the permitting has not been established but the cable is expected to be operating by the end of 2005. The Hunters Point - Martin cable is still in the planning process with a projected operational date of May 2007.

The need for these two cables was identified through the ongoing CA ISO San Francisco Peninsula Study stakeholder process. The study analyzed system reliability using different load scenarios to test the impact of an economic downturn or a significant (400 MW) combination of distributed generation and conservation. Scenarios that analyzed the impact of the closure of existing plants and the potential for new plants were also included. The two cables are needed to alleviate potential reliability problems within the City and County of San Francisco.

Issues and Consequences of Delay. There are several interveners to the Potrero - Hunters Point cable permit process. The biggest conflict may be over PG&E's proposed line route. Because the Martin - Hunters Point 115 kV cable is just in the planning phase no issues have been identified.

The two cable projects reinforce the transmission network inside San Francisco. Without the cables in place in the next ten years, the likelihood of line overloads and blackouts within the city increases.

Metcalf - Moss Landing 230 kV line Reinforcement Project[9]

Project Background. The Metcalf - Moss Landing 230 kV Reinforcement Project consists of upgrading two 230 kV lines. Each line is approximately 35 miles long and the total project will cost between $29 million and $40 million. The CA ISO approved this project in May 2004 and PG&E is currently developing the application for a CPUC permit.

PG&E determined the need for this project in its *2003 Electric Transmission Grid Expansion Plan*. Two transmission alternatives were considered; however, generation and conservation alternatives were not studied. The primary goal of the project, in conjunction with the Tesla - Newark 230 kV upgrade, is to increase the network's ability to serve loads in the San Francisco Bay Area.[10]

Issues and Consequences of Delay. Reconductoring projects, such as this, are usually categorically exempted from major environmental permitting because of their limited impacts. Because these lines pass through environmentally sensitive areas, the exemption may not be granted and this project may require a more thorough environmental impact analysis that could extend the permitting time.

If this project is not completed by 2007, the transmission system in the area will continue to require generation at Moss Landing and Metcalf to reduce output when certain transmission facilities are out of service. This delay could result in reduced electricity supplies and potential shortages if the outages occur during critical hours.

Tesla - Newark 230 kV Upgrade Project[11]

Project Background. The Tesla - Newark 230 kV Upgrade Project is a double-circuit line for all but eight miles of its 28.5-mile length. This project will add a second circuit to the eight-mile single line section and will cost between $5 million and $7 million. This project is not needed to maintain system reliability until after 2007; however, it will have economic benefits beginning in 2005.

This project is in the engineering and construction phase and is expected to begin operating in May 2005. PG&E determined the need for this project in its *2003*

Electric Transmission Grid Expansion Plan. As this project is relatively inexpensive, other alternatives were not considered.[12]

Issues and Consequences of Delay. The upgrade is not needed for system reliability until after 2007. However, the completion of the project will enable the CA ISO to reduce RMR costs (and thus the cost of electricity for ratepayers) enough to make it economically sound to construct the upgrade in 2005.

If the project is not completed by 2005, ratepayers will pay RMR costs that could have been avoided. After 2007, the upgrade is needed for the system to meet reliability standards.

Greater Fresno Area Projects

Two projects, the Gregg-to-Henrietta 230 kV line reconductoring project, and the Gates-to-Gregg 230 kV double-circuit transmission line, have been identified as key projects in the Greater Fresno Area. These projects were first identified as a means to serve growing loads in the Fresno area and to allow for greater use of the Helms Pumped storage plant. Currently, overloads are being avoided on the Gregg - Henrietta 230 kV line through generation dispatch and by limiting the pumping on the Helms Pumped Storage plant. The Gates - Gregg 230 kV project is not needed until after 2012 and has been identified as a long-term need.

Gregg - Henrietta 230 kV Reconductoring Project[13]

Project Background. The Gregg - Henrietta 230 kV line is a 44-mile section of the existing Gates - Gregg 230 kV line. The reconductoring project consists of replacing the current conductors with higher capacity conductors and will cost more than $20 million. The environmental impacts of reconductoring are usually limited, especially in the agricultural region this line passes through. Reconductoring this line will increase the “pumping window” for the Helms Pumped Storage plant, allowing more generation during critical peak-system hours and an increase in the transmission system’s ability to move power into the Fresno area.

This project is still in the planning stage. Because the cost is expected to exceed $20 million, the Gregg - Henrietta 230 kV reconductoring will require CA ISO Board approval. The project has preliminary CA ISO staff approval. The Gregg-Henrietta reconductoring project was identified in the *2003 Greater Fresno Area Long-Term Planning Study*. This study compared a generation alternative, but found the transmission alternative to be superior.[14]

Issues and Consequences of Delay. There are no major issues for the Gregg - Henrietta project. As a reconductoring project with few, if any, impacts, it is expected to be categorically exempt from the CPUC permitting process.

Overloads on the Gregg - Henrietta 230 kV line are currently prevented by temperature-based line ratings, using additional (probably less economic) generation in the Fresno Area, and by limiting the pumping hours at the Helms Pumped Storage plant. Limiting the hours for pumping reduces the power available during peak hours from the Helms plant, which increases the likelihood of supply shortages.

Gates - Gregg 230 kV Double-Circuit Transmission Line[15]

Project Background. The Gates - Gregg 230 kV line would be approximately 60-miles of new transmission line that would significantly improve the system's ability to send power into the greater Fresno area.

This project is in the planning stage. The need for the Gates - Gregg 230 kV was identified in PG&E's *2003 Greater Fresno Area Long-Term Supply Study*,[16] although the study did not indicate a need for the project until after 2012. PG&E included a generation and several transmission options in study. Because of the magnitude of the project, more studies may be required before PG&E receives approval from the CA ISO Board and the CPUC. Because this transmission line would be new, a CPCN will be needed from the CPUC.

Issues and Consequences of Delay. Significant issues that may delay or prevent the permitting of this project will not be known until the planning is complete and the environmental analysis has begun.

The studies show that this project is not needed before 2012. If loads grow faster than expected and generators in the Fresno area shut down, it could be needed sooner.

Sacramento Area Voltage Support Project[17]

Project Background. The Western Area Power Administration (Western) is planning the Sacramento Area Voltage Support Project to meet growing regional loads and maintain system reliability. This three-part project includes reconductoring the 73-mile Elverta-to-Tracy 230 kV double circuit line, constructing a new double-circuit 230 kV line from the O'Banion substation to the Elverta substation, and realigning two other lines. These upgrades are needed to serve growing loads and maintain system reliability in the Sacramento region.

The planning and permitting for this project began in 2000. Several alternatives were considered in the Environmental Impact Statement (EIS) including local generation, however, the transmission alternative was chosen.

The EIS for this project is complete and in December 2003, Western filed a Record of Decision essentially approving the project and choosing from the alternatives analyzed in the EIS. Consultation with other federal and state agencies is still required and may result in minor project modifications.[18] This project does not require CA ISO or CPUC approval.

Issues and Consequences of Delay. No major issues remain for the project, although funding for it needs to be secured. Consultations with the remaining agencies may result in minor project changes.

If the Sacramento Area Voltage Support Project is not completed in time to meet demand growth, electricity reliability in the region will decrease and the risk of power outages will rise.

Summary of Projects to Ensure a Reliable Network

The planning, permitting, and in some cases the construction of transmission projects identified as needed to maintain the reliable delivery of electricity to loads in California has been progressing. Most of the identified projects have been under study since early in 2000 and have recently received permits – a three-to-four year process. This protracted planning and permitting process has given the public and other stakeholders ample opportunity to participate in the project review but has not necessarily produced an in-depth analysis of alternatives to transmission. Because the lengthy planning and permitting review occurred at a time when growth in the California economy slowed considerably, system reliability was not impacted as much as it would have been if load growth had continued at the rates seen in the late 1990s. However, system reliability in California, especially in Northern California, will decrease if these projects are not pursued as quickly as possible.

Projects for Economic Reasons

Many potential transmission projects, while providing some level of improved system reliability, are primarily needed because they will reduce the cost of electricity for ratepayers. All of the high-priority economic transmission projects identified in California are located in or serve the southern portion of the state. All of these projects will increase the transmission system's ability to move power from Northern California, Arizona, or Mexico into Southern California. The need for these facilities has been identified through the analysis of RMR costs, congestion costs, or by identifying long-term opportunities to import low-cost power. These economic projects not only reduce the cost of electricity but also provide insurance or strategic benefits to California ratepayers by expanding potential sources of electricity in the case of protracted line or plant outages or other significant reductions in the electricity supply.

Four of the projects, the Path 26 upgrades, the Tehachapi upgrades, the Short-term Southwest Transmission Expansion Plan (STEP) upgrades, and the Devers - Palo Verde #2 project are located in or connect to the SCE system. The other three projects, the Miguel - Mission 230 kV line, the new line into San Diego (either alternative of the two potential projects under consideration) and the Otay Mesa

Power Purchase Agreement Project, serve the SDG&E system. Overall, these projects could significantly reduce the cost of electricity for California ratepayers, provide insurance and other strategic system benefits, and make it possible for California utilities to meet purchases of renewable energy mandated by the Legislature.

SCE/Los Angeles Area Economic Projects

There are several potential economic projects that could connect to the SCE/Los Angeles transmission network. Three of these projects, the Path 26 upgrades, the short-term STEP upgrades, and the Devers - Palo Verde #2 (DPV2) project, would increase import capabilities into Southern California, providing increased access to lower-cost power and potential insurance benefits. The Tehachapi Area Transmission project is intended to increase transmission from the wind farms in the Tehachapi region to the rest of the Southern California system.

Path 26 Upgrades

Project Background. Path 26 consists of three 500 kV lines and is, in effect, the dividing line between the SCE and PG&E networks. Path 26 has been congested recently, and is one of the critical paths bringing power into Southern California. There are two parts to the Path 26 upgrades, one is a low-cost operational procedure that could increase transmission capacity by 300 MW (from 3,400 MW to 3,700 MW),[19] and the other which includes reconductoring and major equipment upgrades and would increase transmission capacity by as much as 1,000 MW.[20]

The proposed operational procedure would automatically reduce the output of generators north of Path 26 under certain conditions. By instituting this automatic procedure, the CA ISO would be able to protect equipment and allow greater flows on Path 26.

Increasing the Path 26 rating from 3,400 MW to 3,700 MW using operational procedures requires approval from the Western Electricity Coordinating Council (WECC). This project is under review and is expected to be operational in 2005. The reconductoring project is currently in the planning and analysis phase.

Issues and Consequences of Delay. No real issues are involved in instituting the Path 26 rating increase from 3,400 MW to 3,700 MW. The procedures discussed above should be in effect some time in 2005.

The most significant issue surrounding the reconductoring is the magnitude of the economic benefits versus the cost as these lines run through critical habitat for the California condor and other sensitive species. Increasing the transmission network's ability to move power from Northern to Southern California would provide some strategic benefits, but whether these benefits outweigh the project's financial and environmental costs will require more analysis.

Southwest Transmission Expansion Plan (STEP) Upgrades

A consortium of utilities, generators, and other stakeholders in California and the southwestern United States developed the STEP. The plan was driven by electric-power generation development in the Southwest, which could benefit California ratepayers if the transmission paths connecting California and the southwest were improved. The study has identified a series of short-term upgrades. These types of substation improvements are generally exempt from environmental permitting at the CPUC. The second phase of the plan includes major transmission projects including the DPV2 500 kV line and other transmission facilities.

Project Background on Short-term STEP Upgrades[21]. The short-term STEP upgrade incorporates six separate improvements at various substations in Southern California and the Southwest. Included in these upgrades are the following projects: a second 500/230 kV transformer at the Devers substation; upgrading the series capacitors at the North Gila and Imperial Valley substations; upgrading the series capacitors on the Palo Verde - Devers 500 kV line; installing a series reactor on the Devers - San Bernardino #1 230 kV line; installing a 300 megavolt-amp, 230 kV phase-shifting transformer at the Imperial Valley substation; installing dynamic voltage support at the Devers substation; and upgrading the series capacitors on two non-CA ISO transmission lines in Arizona and Nevada. The CA ISO portion of these upgrades will cost approximately $148 million and increase the import capability from Arizona to California by 500 MW. The CA ISO estimated the annual savings to participants at $62 million per year, compared to an annual cost of $26 million.[22]

On June 24, 2004, the CA ISO approved the short-term STEP upgrades. The utilities, SCE and SDG&E, are expected to have these upgrades operational by June 2006.

Issues and Consequences of Delay of short-term STEP Upgrades. While no delays are anticipated, California regulators may increase scrutiny due to the significant project costs ($148 million).

Project Background on DPV2 500 kV transmission line.[23] The proposed project is a 238-mile, 500 kV transmission line that would use the same corridor as the existing Palo Verde - Devers 500 kV line connecting Southern California and Arizona. The project could include several other new lines and is expected to cost between $500 million and $600 million and would not begin operating before 2009.[24]

The DPV2 500 kV line is in the planning phase and will require CA ISO Board approval as well as a CPCN from the CPUC. This project will require more studies before it is brought before these two authorities.

Issues and Consequences of Delay of the DPV2 500 kV Transmission Line. The STEP studies did not analyze the potential strategic benefits of the STEP upgrades and these, as well as additional economic studies, will need to be completed before this project is brought before the CA ISO and CPUC.

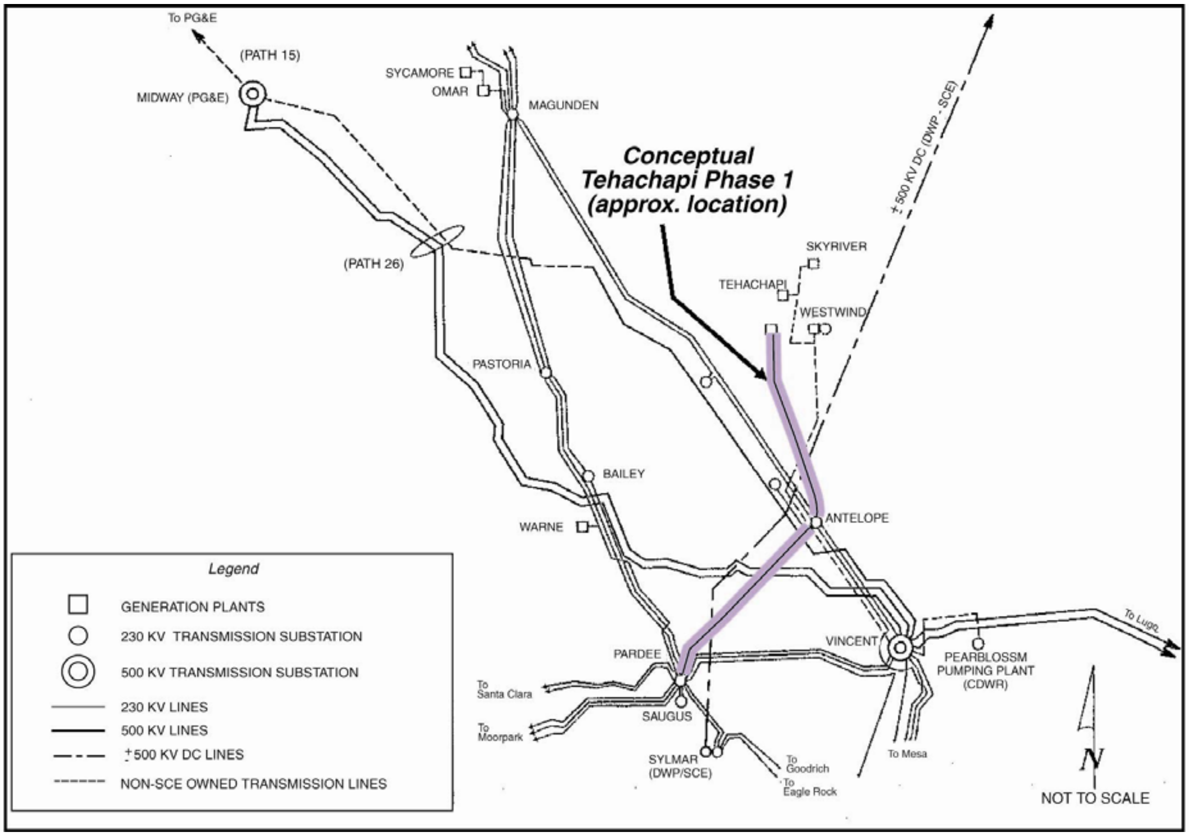
Tehachapi Area Upgrades[25]

Tehachapi area transmission has been congested for many years and upgrades are necessary to insure that California utilities can meet accelerated RPS goals requiring that 20 percent of the utilities' electricity be produced from renewable resources by 2010. On May 10, 2004, the Energy Commission held a workshop in which participants presented various interconnection alternatives for the Tehachapi region. Proposals for upgrading transmission in the region were discussed in the workshop, including new 500 kV and 230 kV systems bringing Tehachapi wind generation into the Southern California area, new lines tying the Tehachapi region into PG&E's system, and combinations of these options. See the "Major Renewable Transmission Projects" section below for a more detailed discussion of transmission constraints in both the Tehachapi and Salton Sea areas.

Project Background. Tehachapi has been identified as a critical area in California's renewable energy development because of its large wind resource. A specific Tehachapi interconnection project has not yet been identified; however, a study group led by the CA ISO and SCE that includes stakeholders and utilities is working to develop a comprehensive Tehachapi phased-development plan by March 2005.

On June 10, 2004 the CPUC ordered SCE to submit an application for a CPCN for the first stage of this development by December 2004, and to develop and submit a plan for the staged interconnection of wind generation in the Tehachapi area by March of 2005. Figure 5-2 shows the approximate location of the conceptual Phase 1 Tehachapi project.

Figure 5-2
Conceptual Tehachapi Phase 1 Project



Issues and Consequences of Delay. The Tehachapi region has experienced congestion related to its wind resource for years. To relieve the existing congestion and allow for the timely interconnection of new resources, SCE must adhere to the current CPUC schedule that calls for a CPCN filing by December 2004 and completion of the phased study by March 2005.

San Diego Area Upgrades

The San Diego area has been subject to a variety of electricity-related concerns over the past few years. Recently, transmission facilities extending from Mexico and the Imperial Valley into San Diego have experienced significant congestion which has cost California ratepayers millions of dollars. Several projects have been identified to both relieve existing congestion and improve the transmission network's ability to move power into the San Diego area.

Miguel - Mission #2 230 kV Transmission Line[26]

Project Background. The Miguel - Mission #2 230 kV transmission line is a 35-mile line costing approximately $31.4 million. A complete description is available in CPUC proceeding A.02-07-022[27]. The decision found that the project would save ratepayers approximately $3 million to $4 million per month in congestion costs.

On July 8, 2004 the CPUC granted SDG&E a CPCN for the Miguel - Mission #2 230 kV project. This project is expected to be operational by June 2006.

Issues and Consequences of Delay. No issues remain for this project.

Lake Elsinore Advanced Pumped Storage (LEAPS) Project

Project Background. The LEAPS project is one of two alternatives that could be developed. It is a 500 kV transmission project associated with a 500 MW pumped storage generation facility proposed for Lake Elsinore in Southern California.

The transmission line would connect SCE's Valley - Serrano 500 kV line to a new substation in SDG&E's territory. This transmission line would be very similar to the Valley - Rainbow line that was denied a CPCN by the CPUC in December 2003.[28] The proposed transmission facilities include an approximately 30-mile transmission line and a new substation. They would cost roughly $170 million. LEAPS would increase the transmission capability from SCE into SDG&E by approximately 750 MW.[29]

The STEP group has analyzed the LEAPS project separately and in conjunction with the Imperial Valley-to-San Diego transmission alternatives. Neither project was found to have annual benefits large enough to offset its costs. Strategic benefits were not analyzed in the study and could improve the projects' economic outlook.

Issues and Consequences of Delay. This is a merchant transmission line project tied to a pumped storage power plant, not subject to state regulation, but under the jurisdiction of the Federal Energy Regulatory Commission (FERC) for licensing.

Imperial Valley – San Diego Expansion Plan[30]

Project Background. This project is the second of two alternatives that could be developed. It is currently being studied as part of the STEP process and will consist of at least one 500 kV connection between the Imperial Valley substation and a San Diego substation. The length of the line would be between 84 miles and 188 miles depending on where the line connects to the San Diego system. The STEP process does not indicate that the benefits of this interconnection outweigh potential costs.

Issues and Consequences of Delay. This project could provide significant strategic benefits by creating a third transmission corridor into San Diego and improving access to generation. Additional studies to determine the potential strategic and insurance benefits would be required to justify the estimated $500 million cost.

Otay Mesa Power Purchase Agreement Transmission Project (OMTP)

Project Background. The OMTP consists of two new 230 kV transmission lines connecting the Otay Mesa power plant to the Sycamore Canyon substation and the Old Town substations in San Diego. The estimated cost of these facilities is $155.7 million. This project is intended to relieve congestion that would prevent power generated by the Otay Mesa Power Plant from reaching load centers in San Diego. By relieving the congestion, the CA ISO could rely on the power plant to provide for local generation needs. This project would then allow the CA ISO to end RMR contracts with other plants in San Diego and would result in net savings of approximately $30 million per year.[31]

SDG&E applied for a CPCN for the OMTP on March 8, 2004. A schedule for this CPCN has not been established, although SDG&E has proposed that a formal decision be made in March 2005.

Issues and Consequences of Delay. Several parties have filed protests to this process, including the Office of Ratepayer Advocates, the Border Generation Group, and the City of Chula Vista. This project raises complex planning issues that have not been addressed before in California. SDG&E has signed a long-term power purchase agreement with the owners of the Otay Mesa power plant. To receive the maximum value from this contract, SDG&E needs to construct two transmission lines, neither of which was considered with the cost of the purchase agreement.

Projects for Renewable Energy Development

The acceleration of renewable energy project development initiated by the Renewables Portfolio Standard (RPS) has highlighted the role that transmission plays in some renewable energy resource development. Transmission interconnection issues for renewable resources located in concentrated areas such as the Tehachapi Wind Resource Area and the Salton Sea Area are complicated by the number of owners/developers competing to develop their projects, as well as limited or, in some cases, the transmission lines are non-existent making these renewable resources inaccessible. For a further discussion of renewable energy, please see the Energy Commission report, *Accelerated Renewable Energy Development Draft Staff White Paper*.[32]

On May 10, 2004 the Energy Commission held an IEPR Committee workshop to explore potential issues for renewable power development in California. The workshop focused primarily on two regions, the Tehachapi wind region and the Salton Sea geothermal area. Both areas have the potential for significant renewable energy project development that could be slowed or hindered by transmission issues. Participants included California electric utilities, wind developers, the

California Independent System Operator (CA ISO) and other stakeholders. If the transmission network to interconnect renewable resources is not carefully planned, a piecemeal system that increases costs and uses unnecessary right-of-way could result.

Tehachapi

The Tehachapi region currently connects to Southern California utilities (SCE and the Los Angeles Department of Water and Power, LADWP) through three 230 kV lines. These lines include the privately owned Sagebrush 230 kV line, SCE's 230 kV Big Creek system, and LADWP's Owens Gorge - Rinaldi 230 kV line. The transmission network out of Tehachapi is now fully loaded and will need to be expanded to accommodate any significant new wind development. Two other major transmission paths, one of the 500 kV lines that make up Path 26 and the 500 kV Pacific Direct Current Intertie (PDCI), are within 20 miles of potential wind development. The planning and development for the expansion of the Tehachapi transmission network is complex, with many developers, options, and opinions.

Several participants at the May 10, 2004 IEPR Committee workshop focused their presentations on the Tehachapi wind area. These participants included representatives from SCE, the CA ISO, PPM Energy and Oak Creek Energy Systems. The following are brief summaries of their presentations.

Summary of SCE Presentation

SCE recommended that the state proceed carefully. Operational issues need to be considered, as well as interconnection issues. (See section below entitled "Operational Issues for Integration of Renewables.")

SCE noted that developing a plan to interconnect 4,000 MW of new wind generation is a good exercise. To plan for generation interconnection, the sensible method is to analyze the transmission needs of individual generators first and then the system as a whole to see if these needs can be combined.

Any plan that is developed should be flexible to accommodate staged resource development and multiple buyers, and to avoid piecemeal decision making and "free riders."

Summary of CA ISO Presentation

The CA ISO had no preconceived notions about what is the best plan for the Tehachapi region; however, the plan should consider potential system-wide benefits. The CA ISO indicated it was prepared to coordinate a Tehachapi area study group.

Several interconnection alternatives include the following:

- A Midway-Tehachapi-Vincent 500 kV line which could increase Path 26 transfer capability while providing an outlet for Tehachapi wind generation.

- Tie SCE's Big Creek system into PG&E's Greater Fresno Area network. This connection would increase the network load-serving capability in the Fresno Area and accommodate increased generation at the Helms Pumped Storage plant.

- Add a second circuit to the privately owned Sagebrush 230 kV line. The potential for flexible alternatives exists where a double circuit tower could be fitted with one circuit until the second circuit is needed, or 500 kV towers could be fitted with 230 kV until the upgrade to 500 kV was warranted.

Summary of Oak Creek Energy Presentation

Around 5,000 MW of developable wind resources are in the area, and if issues with the military are resolved, even more resources would be available.

Something should be done soon. Take the Pardee – Antelope -Tehachapi 230 kV line as a first step, then plan the rest in detail. Significant capacity could be available on the privately owned Sagebrush 230 kV line.

LADWP owns the Owens Gorge - Rinaldi 230 kV line and may build another line. These lines are not integrated into the CA ISO system, but they should not be left out of any Tehachapi area planning.

The 500 kV PDCI, which runs right through the Tehachapi area, may have a lot of unused capacity.

Adding a fourth Path 26 circuit should be analyzed to determine its ability to provide an outlet for wind sales to PG&E, as well as to reduce congestion on the existing path.

The dynamic rating of conductors should be explored as a way to increase the available transmission capacity.

Salton Sea

Two participants at the May 10, 2004 workshop focused their presentations on the Salton Sea geothermal area transmission issues. The following section summarizes presentations by representatives of the Imperial Irrigation District (IID) and Cal Energy.

Summary of Imperial Irrigation District Presentation

The pathways out of the IID's network are congested but could be expanded. Both Path 42, connecting to the SCE system, and lines connecting to SDG&E are congested and could not support more geothermal generation in the Salton Sea area.

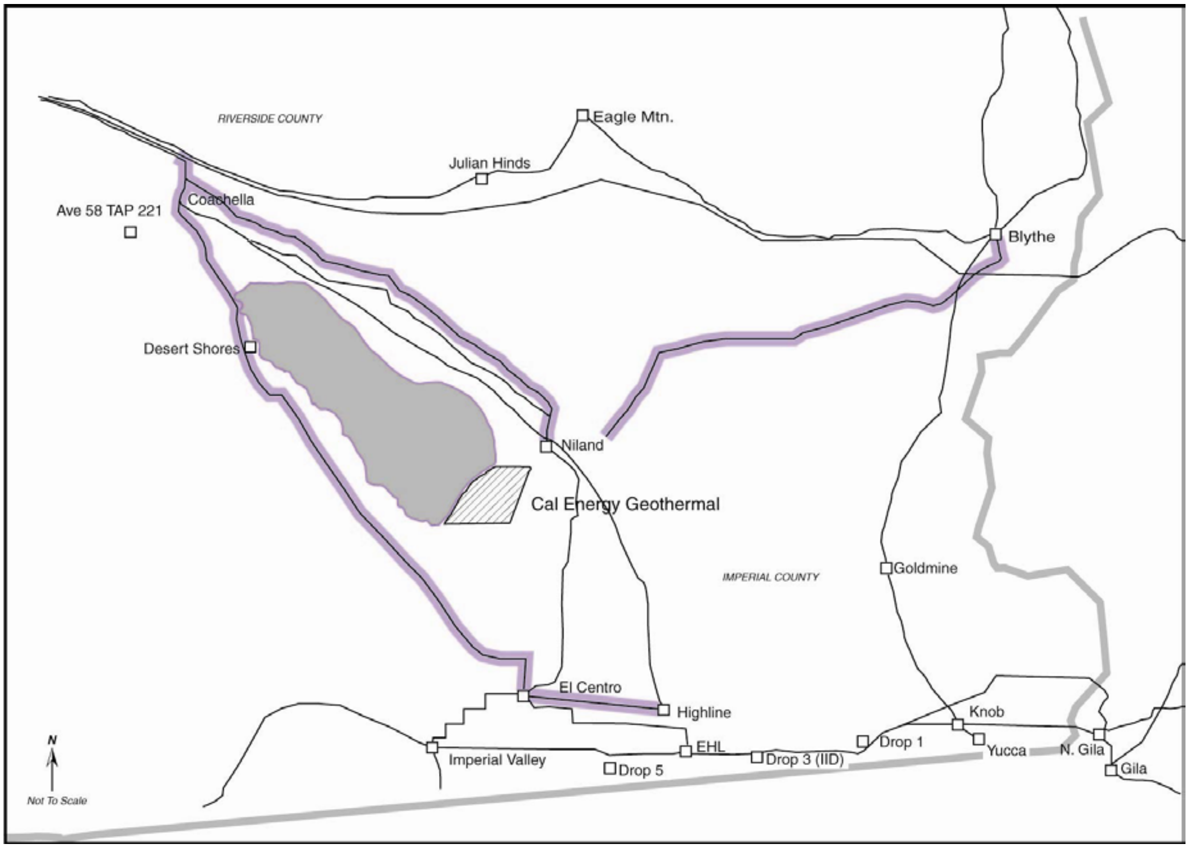
IID has a two-stage plan for accommodating new geothermal generation. The first stage would accommodate 600 MW of new geothermal generation (see Figure 5-3) that includes the following projects:

- Upgrading Path 42 to two conductors per phase;
- Connecting the Coachella Valley Switching station to the 500 kV transmission network east of the Devers substation;
- Upgrading IID's existing 161 kV and 230 kV transmission lines; and
- Building a 230 kV line between the El Centro Switching Station and the Highline substation.

The second stage would accommodate up to 2,200 MW of new geothermal generation and would include:

- Looping the proposed 500 kV line from IID to SDG&E into a substation near the Salton Sea area and,
- Constructing a new 500 kV line from the Midway or Bannister substation to the Coachella Valley/Devers switching station.

Figure 5-3
Possible Salton Sea Upgrades Proposed by IID



The systems analysis studies have not been done for either stage of this plan and would be the logical next step. More financial support would be needed for the environmental work.

Summary of Cal Energy Presentation

Cal Energy recognized that congestion problems at the Miguel substation and on Path 42 need to be addressed, as the company has plans to develop 600 MW of geothermal generation by constructing one 200 MW plant every two years starting in 2009. The plans could be expedited to develop all 600 MW by 2010. An additional 1,100 to 1,200 MW could be available for development after 2013. Cal Energy noted that the internal IID system is not sufficient for even one more 200 MW plant. The company would prefer interconnection to CA ISO at Mirage/Devers substations and/or at the Imperial Valley substation and to the Western Area Power Administration at the Blythe substation.

Cal Energy also stressed that a major issue facing development in this area is who pays for the transmission facilities. Interconnection/system studies will be needed to determine the final interconnection plan.

May 10, 2004 Workshop Round Table Session

Other participants echoed most of these thoughts during the roundtable discussion at the May 10, 2004 workshop. The following is a summary of their comments:

- The Valley Group noted that wind generation and dynamic rating of transmission lines are a perfect match. Wind generators produce electricity when the wind blows which is also when conductors would be rated at their highest levels.

- The League of Women Voters commented that the long-term plan needs to be statewide and look beyond 2010, to accommodate renewable energy needs in 2030.

- The Naval Air Systems Weapons Command stressed that wind resources development and the associated transmission facilities need to be coordinated with the military.

- The CA ISO urged a continuous update of the Energy Commission's renewable energy forecast to help planners working on the Tehachapi area transmission plan.

- PPM commented that the study should not get so big that near-term, high-priority projects are overlooked. There seems to be consensus on what Phase 1 should encompass, and is a good beginning for further study.

- LADWP wanted to be sure that the possibility for utility-owned generation resources was not left out.

- Oak Creek Energy Systems wanted the planning process to be transparent with information available to all stakeholders.

- IID indicated that California needs an expedited transmission permitting process and mechanism for funding regional studies for Salton Sea and Tehachapi.

- SDG&E noted connecting renewables to the system is more complex than just "building wires." Other issues, like system ramp rates and var support must not be forgotten. The Energy Commission should study these issues in the 2005 Energy Report.

- Cal Energy commented that energy storage may be an important component of renewable energy development in California.

Operational Issues for Integration of Renewables

A substantial increase in renewable generation, such as wind, is likely to raise operational and resource integration issues that may hinder and delay renewables development. The first area in which these issues will need to be addressed will be in concert with the staged development plan for Tehachapi that the CPUC initiated in its proceeding I.00-11-001, Phase 6.

The issues, as outlined by SCE and as echoed by SDG&E, at the May 10, 2004 workshop are summarized below:

- An interconnection must be adequate to accommodate the amount of energy that the wind generators are able to produce. Conceptually, for Tehachapi, a collector system from the various wind parks is required to deliver the power to a new substation at the northern end;

- With regard to ramp rate and system frequency, spinning reserve “offsets” must be identified and available throughout the control area to prevent unacceptable frequency fluctuations. The CA ISO would need to have identified generators across the state that have the ability to offset the renewable generation in very exact amounts to control 60 Hertz frequency, so that as renewable generation ramps up, the identified generation ramps down. The potential in the Tehachapi area could be as high as 8,000 MW an hour; and

- With regard to var consumption, sufficient dynamic voltage support must be available in adequate amounts if adequate var is not available. However, new technology is better at managing var consumption rates than past technology. Planners need data on the specific equipment that would be used to address how that machinery would impact the voltage in the area.

Recommendations

The Energy Commission staff recommends that the following actions be pursued in support of the 2005 Energy Report:

- Continue to update the *Transmission Project Watch List of Projects Under Evaluation* in consultation with the agencies and staff who have collaborated on the *Energy Action Plan*.

- Participate in the Study Group for Phased Tehachapi Transmission Development in CPUC proceeding I.00-11-001, Phase 6, led by SCE and the CA ISO.

- Form a similar study group focused on developing a transmission plan for the Salton Sea Geothermal area.

- Initiate a study for the 2005 Energy Report process to assess the reliability and operational issues associated with the timely integration of renewables into California's transmission system. This study would be based upon the experience and best practices from other regions for integrating large amounts of renewables The lessons learned would assist in establishing a state policy framework for addressing these issues.

Endnotes

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[3] California Independent System Operator, Board of Governors report 4/22/2004.

[4] Pacific Gas & Electric, *PG&E's 2003 Electric Transmission Grid Expansion Plan*. P. 1-14. December 11, 2003.

[5] Ibid, page 1-5.

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[21] Southwest Transmission Expansion Plan 2003 Status Report, March 8, 2004. Pages 20-23.

[22] CA ISO Board Approval of STEP short-term transmission upgrades.

[23] Ibid, pages 33-46.

[24] Ibid, page 61.

[25] Interim Opinion on Transmission Needs in the Tehachapi Wind Resource Area, California Public Utilities Commission decision 000-11-001. Pages 1-4.

[26] Final Decision – D.04-07-02, July 8, 2004.

[27] http://www.cpuc.ca.gov/Environment/info/aspen/miguel_mission/miguelmission.htm

[28] Draft Application for License of Major Unconstructed Project, Lake Elsinore Advanced Pumped Storage Project, FERC #11858.Pages E1-10 to E1-12.

[29] STEP Economic Study Updates, Mohamed Awad CA ISO, May 27, 2004.

[30] Ibid.

[31] Calpine Letter of May 12, 2004 to Commissioners Brown and Wood, RE: R.01-10-024; Calpine's Response to Questions Raised at the May 3, 2004 All-Party Meeting Addressing the Proposed and Alternate Decisions Approving Power Procurement Contracts Resulting from SDG&E's Grid Reliability RFP, p. 4.

[32] California Energy Commission. A*ccelerated Renewable Energy Development,* Staff white paper. July 2004. Publication number 100-04-003 [http://www.energy.ca.gov/reports].

GLOSSARY

CA ISO control area – The electrical region under the operational control of the CA ISO.

Constraints – Physical and operational limitation in the transfer of electrical power through transmission facilities.

Demand-side management – Measures taken by a utility or control area operator to influence the level or timing of customers' energy demand to optimize the use of available resources.

Double circuit AC transmission line – Two three-phase single-circuit transmission lines (a total of six conductors) supported by single pole or tower structures.

Electric and Magnetic Fields – Energy fields that result from the existence and movement of electric charges. Electric and magnetic fields occur naturally and can also be created. Electric fields are present wherever electric charge exists, and magnetic fields result from the movement of these electric charges.

Investor-owned utility (IOU) – A utility entity whose assets are owned by investors.

Kilovolt (kV) – One thousand volts.

Kilowatt (kW) – One thousand watts. A unit of measure of the amount of electricity needed to operate given equipment.

Kilowatt-hour (kWh) – The most commonly used unit of measure telling the amount of electricity consumed over time. It refers to one kilowatt of electricity supplied for one hour.

Megavolt ampere (MVA) – One minion volt-amperes.

Megawatt (MW) – One thousand kilowatts, or one million watts.

Megawatt-hour (MWh) – One thousand kilowatt hours.

Municipal utility – A local publicly-owned electric utility that owns or operates electric facilities subject to the jurisdiction of a municipality, as opposed to being subject to FERC or CPUC jurisdiction.

Publicly-owned utility – A municipal utility, irrigation district, or federal power marketer. Examples include the Sacramento Municipal Utility District, the Imperial Irrigation District, and the Western Area Power Administration.

Reliability – The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amounts desired. May be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.

Reliability criteria – Principles used to design, plan, operate, and assess the actual or projected reliability of an electric system.

Reliability Must Run (RMR) generation – The minimum generation (number of units or MW output) required by the CA ISO to be on line to maintain system reliability.

Renewable energy – Energy resources that constantly renew themselves or that are regarded as practically inexhaustible. These resources include solar, wind, geothermal, hydroelectric, and waste-to-energy.

Var – Volt-ampere reactive (var) is a measure of reactive power, which is not capable of doing work but must be present in an alternative current circuit to operate certain types of equipment.

Volt – A unit of electromotive force. It is the amount of force required to drive a steady current of one ampere through a resistance of one ohm.

ACRONYMS

AC – Alternating Current

AFC – Application For Certification

ALJ – Administrative Law Judge

BPA – Bonneville Power Administration

CA ISO – California Independent System Operator

CBE – Communities for a Better Environment

CC – Combined Cycle

CEQA – California Environmental Quality Act

CERTS – Consortium of Electric Reliability Technology Solutions

CHP – Combined Heat and Power

CMTA – California Manufacturers and Technology Association

CPA – Consumer Power and Conservation Financing Authority

CPCN – Certificate of Public Convenience and Necessity

CPUC – California Public Utilities Commission

CSP – Concentrating Solar Power

CT – Combustion Turbine

DC – Direct Current

DG – Distributed Generation

DOE – U.S. Department of Energy

DPV2 – Devers-Palo Verde 2

DSM – Demand-Side Management

DSW – Desert Southwest

DWR – California Department of Water Resources

EAP – Energy Action Plan

EHV – Extra High Voltage

EIS – Environmental Impact Statement

EIR – Environmental Impact Report

EMF – Electric and Magnetic Fields

ENGAR – Electricity and Natural Gas Assessment Report

ER – Energy Report

FERC – Federal Energy Regulatory Commission

GGNRA – Golden Gate National Recreation Area

GIS – Geographic Information System

GO – General Order

IEPR – Integrated Energy Policy Report

IID – Imperial Irrigation District

IOU - Investor-owned Utility

kV – Kilovolt

kWh – Kilowatt-hour

LADWP – Los Angeles Department of Water and Power

LE – London Economics International LLC

LEAPS - Lake Elsinore Advanced Pumped Storage

LOLP – Loss of Load Probability

LRA – Local Reliability Area

MISO – Midwest Independent System Operator

MLVKGRA – Mono-Long Valley Known Geothermal Resource Area

MP – Mountain Pacific

MSW – Municipal Solid Waste

MVA – Megavolt-ampere

MW – Megawatt

MWh – Megawatt-hour

NEPA – National Environmental Protection Act

NERC – North American Electric Reliability Council

OII – Order Instituting Investigation

OIR – Order Instituting Rulemaking

O&M – Operation and Maintenance

OMTP – Otay Mesa Transmission Project

ORA – Office of Ratepayer Advocates

OTC – Operation Transfer Capability

PG&E – Pacific Gas and Electric

PIER – Public Interest Energy Research

PHFU – Plant Held for Future Use

PJM – Pennsylvania – New Jersey – Maryland Independent System Operator

PNW – Pacific Northwest

PTC – Permit To Construct

PRC – Public Resources Code

PV - Photovoltaic

PWG – Planning Work Group

R&D – Research and Development

RMATS – Rocky Mountain Area Transmission Study

RMR – Reliability Must Run

ROW – Right-of-Way

RPS – Renewables Portfolio Standard

RTO – Regional Transmission Organization

SANDAG – San Diego Association of Governments

SB – Senate Bill

SCE – Southern California Edison

SDG&E – San Diego Gas and Electric

SDREO – San Diego Regional Energy Office

SFPUC – San Francisco Public Utilities Commission

SSCDC – Southeast Sector Community Development Corporation

SSG-WI – Seams Study Group – Western Interconnection

STEP – Southwest Transmission Expansion Plan

TEAM – Transmission Economic Assessment Methodology

Var – Volt-ampere reactive

UCAN – Utility Consumers' Action Network

WECC – Western Electricity Coordinating Council

Western – Western Area Power Administration

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APPENDIX A: DEVELOPMENT OF A TRANSMISSION VISION FOR CALIFORNIA

Purpose

In view of the long-lived nature of transmission lines and the ever-increasing difficulty of planning and permitting for needed transmission projects in a manner that addresses the sometimes competing objectives of system reliability, cost-effectiveness, and minimized public health and environmental impacts, the Energy Commission staff began the process of developing a long-term vision for California in this 2004 Integrated Energy Policy Report Update (2004 Energy Report Update) process. A long-term vision of the state's transmission system developed in a collaborative manner can provide the framework for making intelligent choices now with respect to the type, size, location, value, cost, function(s), and operational characteristics of future transmission projects, as well as future transmission corridors and rights-of-way. In this manner, California can maximize its ability to plan, permit, construct, and operate its transmission system in a manner that achieves state objectives while also considering impacts to California's citizens, environment, and neighbors.

2004 Update Process for Developing a Long-term Transmission Vision

The following sections describe the Energy Commission staff's efforts undertaken in this 2004 Energy Report Update process to solicit and consider input from a wide range of stakeholders on the topic of a long-term transmission vision for California.

April 5, 2004 Energy Report Committee Workshop

At the request of the Energy Commission, the Electric Power Group of the Consortium of Electric Reliability Technology Solutions (CERTS) prepared a report to begin the process of developing a long-term vision for California's electricity transmission system. The report provides interested parties with a perspective on the magnitude of the challenge facing the state as it seeks to meet consumers' electricity demand through the year 2030, and why it is important to have a vision today of how the transmission system should evolve to meet these challenges. The report, entitled *California's Electricity Generation and Transmission Interconnection Needs Under Alternative Scenarios* (Pub. No. 700-04-003), can be found at:

http://www.energy.ca.gov/2004_policy_update/documents/index.html

The Energy Commission staff initiated a process for collaborating with interested parties on the development of a long-term vision for the state's transmission system for eventual use in developing state policy. The staff described potential drivers affecting the development of a vision and then sought input from interested parties on the following questions:

1. What additional drivers need to be considered in developing a long-term transmission vision?
2. What do you see as the vision for California's transmission system?
3. What steps need to be taken in this 2004 Energy Report Update?
4. What steps need to be taken in the 2005 Energy Report Proceeding?

Nineteen people participated in the round-table discussion, providing their perspectives on the necessary components of a transmission vision. The transcripts for the entire workshop [placed online on April 15, 2004] can be found on the Energy Commission's website at:

http://www.energy.ca.gov/2004_policy_update/documents/2004-04-05_workshop/2004-04-05_TRANSCRIPT.PDF

The Energy Commission staff received additional written comments from five interested parties following the workshop. These comments are available on the Energy Commission's website at:

http://www.energy.ca.gov/2004_policy_update/documents/2004-04-05_workshop/public_comments/

The Energy Commission staff then summarized and published a synopsis of all of the comments received at and after the April 5 workshop. This synopsis may be found on the Energy Commission's website at:

http://www.energy.ca.gov/2004_policy_update/documents/2004-04-05_workshop/2004-05-05_SUMMARY.PDF

The staff's goal was to develop a transmission vision statement based on the input received at and after the April 5, 2004 workshop. However, in the process of summarizing the workshop comments, the staff found that the range of comments was so diverse as to require it to first look for areas of consensus and common themes in the comments before drafting a vision statement.

The staff found that many of the comments expressed were potentially in conflict with one another. For example, a common theme expressed was that the transmission system has great value to California, while at the same time parties recognized that transmission is only one piece of the state's energy infrastructure. Many parties agreed that the timing is right to develop a long-term transmission vision, but they also acknowledged that short-term actions should be taken now. Another common theme was the need to plan ahead for corridors and to set aside rights-of-way for future projects, but some parties also stressed the importance of making more efficient use of the existing system. Some parties expressed the importance of planning for transmission needs on a regional basis with consideration for California's neighbors, while others believed the vision should focus on solving local reliability problems. Some parties expressed the importance of ensuring that the vision demonstrates a commitment toward environmental stewardship and respect for the people affected, while others believed that land use constraints in certain areas are so great that the only viable option is to re-designate state- or federal-owned land for transmission purposes.

Given all of this potentially conflicting input, the staff distilled the comments into a set of principles upon which a vision statement could be constructed, and sought feedback on the principles as an intermediate step to developing a vision. To that end, the staff compiled the following principles:

1. Be long-lasting (but not inflexible).
2. Contribute toward a sustainable energy future.
3. Create a system that can handle unpredictable conditions such as load growth patterns and market dynamics.
4. Guide both long-term and short-term needs, although not necessarily to the point of specific transmission projects being prescribed. However, it should pave the way for future transmission projects that are in the best interests of the state when compared on an equal basis with other alternatives.
5. Consider California's neighboring states and countries, as well as local areas and citizens. To that end, the Energy Commission should work with other state, county, and city agencies and stakeholders as it develops the vision.
6. Begin as soon as possible to maximize the vision's value to California's citizens and prevent the foreclosure of opportunities for an optimized electricity-delivery system.

As noted above, although the majority of the stakeholder comments were focused on a long-term vision for transmission, a number of specific actions were mentioned by stakeholders that can be undertaken now. One high-priority, near-term action is to look into corridor planning and land use banking. Parties saw this effort as a means to take lower-cost actions now that could pay off at a future date when specific new transmission projects are found to be the most effective means to meet California's needs.

Another near-term action is to investigate technologies that allow the existing system to be used more efficiently. To that end, the Energy Commission is funding a number of system improvements via its Public Interest Energy Research (PIER) program.

May 10, 2004 Energy Report Committee Workshop

At the May 10, 2004 workshop, the staff sought feedback from interested parties on three topics: (1) the accuracy and completeness of the staff's synopsis of comments received at and after the April 5, 2004 workshop; (2) the accuracy and completeness of staff's synthesis of the major guiding principles for a transmission vision noted above; and (3) the two specific near-term actions noted above.

The staff's presentation is available on the Energy Commission website at:

http://www.energy.ca.gov/2004_policy_update/documents/2004-05-10_workshop/2004-05-10_JGRAU.PDF

The staff did not receive any oral comments on any of these three topics at the May 10 workshop. (See the transcripts for the entire workshop [placed online on May 20, 2004], which can be found on the Energy Commission's website at:

http://www.energy.ca.gov/2004_policy_update/documents/2004-05-10_workshop/2004-05-10_TRANSCRIPT.PDF

Although the staff did not receive any written comments from stakeholders that specifically addressed the three topics noted above, three parties (Donald Clary on behalf of the Pechanga Band of Luiseño Mission Indians, Robert Sullivan of Mammoth Pacific, L.P., and Bernie Orozco of Sempra Energy) did make comments that speak toward the topic of a transmission vision. Their comments are available on the Energy Commission website at:

http://www.energy.ca.gov/2004_policy_update/documents/2004-05-10_workshop/public_comments/

Their comments can be summarized as follows:

- Native American tribes must be an important part of any transmission planning process, and the transmission vision must expressly address and encourage their participation.
- Tribal concerns regarding sovereignty and historical and cultural resources must be dealt with more than just superficially.
- Tribes need to be compensated appropriately for rights-of-way and easements.
- The vision must encourage development through an inclusive process.
- Actual project plans must accommodate energy needs on impacted reservations.
- Transmission is only one of the many planning considerations that communities face.
- Tribes (and others) need to have resources provided to them in the transmission planning process.
- The Energy Commission should consider the impact of aging and inefficient lines that limit access to renewables, contribute to line losses, and have high maintenance requirements, such as Path 60.
- An integrated energy policy should identify transmission expansion needs to ensure access to the optimum mix of long-term energy resources.
- The Energy Commission's vision to plan ahead for corridors and set aside rights-of-way is an appropriate action to provide guidance for long-term transmission planning.
- The state needs to accommodate the possibility of corridors through federal and state lands.
- State agencies need to work together to expedite the transmission licensing process.

June 14, 2004 Energy Report Committee Workshop

Given all of the input received to date, the staff developed a draft transmission vision statement and the elements which comprise it (see Figure A-1.) The staff presented this vision statement at the June 14, 2004 workshop for review and comment, along with an update to stakeholders on input received at and after the May 10, 2004 workshop, with a discussion of next steps.

The staff then sought input from interested parties on the following questions:

1. Does this vision statement and its elements provide the proper guidance to policymakers in choosing the future direction of California's transmission system?
2. Is it complete? Are there other elements that should be considered?
3. Should the elements be prioritized?
4. How do we implement the vision?

The staff did not receive any oral comments on any of these four questions at the June 14 workshop. The transcripts for the entire workshop [placed online on June 28, 2004], can be found on the Energy Commission's website at:

http://www.energy.ca.gov/2004_policy_update/documents/2004-06-14-workshop/2004-06-14_TRANSCRIPT.PDF

Figure A-1
Staff Draft Vision Statement
(Source: California Energy Commission, available on the Energy Commission website at:
http://www.energy.ca.gov/2004_policy_update/documents/2004-06-14-workshop/2004-06-14_VISION_STATE.PDF)

It is the vision for the State of California to have a bulk transmission system that is planned, permitted, constructed, and operated in a manner that effectively balances the needs for a safe, reliable, cost-effective, and environmentally sensitive electricity system.

This vision is comprised of the following elements:

- It is coordinated with, and effectively considers, the needs of California's residential, commercial, and industrial customers;
- It is coordinated with, and effectively considers, the needs of local agencies, jurisdictions, and sovereignties;
- It encourages continuing beneficial interchanges with California's neighbors;
- It allows for the implementation of a portfolio approach to solving California's electricity requirements while contributing to a sustainable electricity future;
- It values strategic benefits when considering system upgrades, including the ability to respond to unpredictable future conditions;
- It encourages making low-cost investments now in order to preserve opportunities in the future, especially with respect to corridor planning and set-aside;
- It encourages continuous improvements through investments in transmission R&D (both hardware and software); and
- It promotes the application of the Senate Bill 2431 (SB 2431, Chapter 1457, Statutes of 1988, Garamendi) siting principles to maximize efficient use of the existing transmission system.

Only one set of written comments was received after the workshop that included comments about the development of a transmission vision, in particular with respect to the inclusion of strategic benefits in that vision. These comments, from Dr. Andrew Van Horn and Dr. Keith White of Van Horn Consulting, can be summarized as follows:

- The Energy Commission's strategic perspective includes "vision" or principles, as well as concrete objectives such as the identification and preservation of specific transmission corridors. Articulating these objectives requires procedures and tools for constructing, evaluating, and discussing long-term transmission scenarios and strategies to make the vision understandable to stakeholders and defensible to decision-makers.

- To provide meaningful guidance for shorter-term decisions and stakeholder/public input, strategic "vision" and principles must be tested by a structured, more transparent process.

- The Energy Commission's strategic vision and tools must be sufficiently explicit and structured to show specifically how the implementation of the strategic vision will help avoid or improve identified near-term problems.

- If the methodology is not sufficiently structured and detailed for quantifying and stress-testing the Energy Commission's "strategic vision," then the vision will be of limited use in guiding actual transmission decisions.

Recommendations and Next Steps

The staff appreciates the input it has received to date from stakeholders on the vision topic. However, given the importance of achieving a vision that represents a consensus view and guides future state policy, and the lack of input received on the draft vision statement presented in Figure A-1, the staff believes it is premature to adopt the draft vision statement at this time.

It would be appropriate for the 2005 Energy Report process to take up the development of a transmission vision, using the 2004 Energy Report Update work as a starting point. It may be appropriate to integrate the transmission vision into an overall vision that considers all facets of the energy sector. Deferring any immediate decisions on the transmission vision until the 2005 Energy Report process will allow the staff to find additional ways to encourage a broader range of stakeholder participation, thereby ensuring that a true consensus is reached.

As noted earlier, two high-priority near-term actions were identified by stakeholders at the April 5, 2004 Committee workshop. One high-priority near-term action is to look into corridor planning and land use banking. The Energy Commission staff has already begun this effort. For more details on the specific recommendations for this effort, see Chapter 3 entitled, "Transmission Corridor Planning and Development."

Another near-term action identified by stakeholders is to investigate technologies that allow the existing system to be used more efficiently. To that end, the Energy Commission is funding a number of system improvements via its PIER program. For more information on the PIER program relating to research and development on improving the reliability and efficiency of the transmission grid, see the Energy Systems Integration program area under the Energy Commission's PIER program page, at:

http://www.energy.ca.gov/pier/strat/index.html

APPENDIX B: JUNE 2004 INTEGRATED ENERGY POLICY REPORT COMMITTEE WORKSHOP

Workshop Overview

This appendix is a compilation of major comments made and issues raised at the June 14, 2004 Commission panel discussion and workshop, the fourth in a series of events for the 2004 transmission update process. The purpose of the transmission effort in 2004 is to further the *2003 Integrated Energy Policy Report* (*2003 Energy Report*) goals. The *2003 Energy Report* brought forward the importance of modernizing and upgrading the bulk transmission grid; and identified both planning and permitting actions that the State should take to improve the system in a cost-effective, environmentally sensitive manner that insures a reliable, robust system. The goal of the workshop was to examine how alternatives to transmission expansion have been considered up to that point in the planning and permitting spectrum.

At the beginning of the workshop, Susan Lee, from the Aspen Environmental Group, presented a summary of the *Comparative Study of Transmission Alternatives* consultant report, which was prepared for the workshop. Four presentations were also given by the following participants on alternatives to transmission system expansion. Armando Perez from the California Independent System Operator (CA ISO) discussed the assessment of transmission alternatives in the grid planning process. Barbara Hale from the California Public Utilities Commission (CPUC) talked about the assessment of alternatives in the resource procurement process. Ed Smeloff from the San Francisco Public Utilities Commission (SFPUC) examined alternatives in the development of a comprehensive local area energy plan. Greg Karras from Communities for a Better Environment (CBE) presented observations and recommendations on the adequate treatment of alternatives in the current processes.

Following the presentations, Commissioner John L. Geesman, Presiding Member, 2004-2005 Integrated Energy Policy Report (IEPR) Committee, and Commissioner James Boyd, Associate Member, sought input from panelists and interested parties on how, where, and when alternatives should be assessed in the transmission process in the future. Table B-1 lists those panelists and interested parties who participated in the panel discussion at the workshop. A summary of the comments received during the panel discussion is presented below.

Table B-1
Workshop Participants and Affiliations

Participant	Affiliation
Commissioner John Geesman	Presiding Member
Commissioner James Boyd	Associate Member
Joe Eto (facilitator)	Lawrence Berkeley National Laboratory, Consortium for Electric Reliability Technology Solutions
Roland Schoettle	Optimal Technologies International Inc.
David Olsen	Center for Energy Efficiency and Renewable Technologies
Steven Kelly	Independent Energy Producers Association
Mark Ward	Los Angeles Department of Water and Power
Morteza Sabet	Western Area Power Administration
Chifong Thomas	Pacific Gas and Electric Company
Maury Kruth	Transmission Agency of Northern California
Dan G. Ozenne	San Diego Gas and Electric Company/Sempra Energy
Patricia Arons	Southern California Edison Company
Armando Perez*	California Independent System Operator
Barbara Hale*	California Public Utilities Commission
Ed Smeloff*	San Francisco Public Utilities Commission
Greg Karras*	Communities for a Better Environment
Fred Mobasheri	Electric Power Group
Anjali Sheffrin*	California Independent System Operator

Source: Oral comments received at the California Energy Commission, Hearing Room A, on Monday, June 14, 2004

* Indicates panelists who also gave presentations during the workshop.

In the afternoon, Energy Commission staff gave an update on its continuing efforts to define and develop a transmission corridor study and a long-term transmission vision. Presentations were also given by Dr. Anjali Sheffrin from the CA ISO on the Transmission Economic Assessment Methodology (TEAM), Dr. Mingxia Zhang from the CA ISO on market -based simulation in the CA ISO TEAM, Joe Eto representing Consortium for Electric Reliability Technology Solutions (CERTS) on the most recently report prepared by the Electric Power Group for the Energy Commission on the valuation of the strategic benefits of transmission interconnection, and finally Kristy Chew presented an Energy Commission staff update on the Southern California transmission corridor study process.

Summary of the Panel Discussion

Presented below is a summary of each participant's comments during the panel discussion on how, where and when alternatives should be assessed in the process.

Roland Schoettle, Optimal Technologies International Inc.

The grid ***is*** the issue. It is difficult to define what the grid actually is and how it is interconnected with the different pieces.

His company, Optimal Technologies International Inc. (OTII), has developed a new optimization technology that allows a deeper look into the grid, with a higher degree of granularity than what is possible now. With this technology, various perspectives and scales can be analyzed, including details that are not included in the regular supply/demand balance. This enhanced capability enables an understanding of where precisely the grid boundary is and all of the options that are available at the time.

Although individual components are important assets, planners should concentrate on the technical side and should look at the entire grid as their primary asset. Understanding the grid in this granular, yet holistic, approach is where the transmission grid planning needs to go in the future.

Dave Olsen, Center for Energy Efficiency and Renewable Technologies (CEERT)

The Rocky Mountain Area Transmission Study (RMATS) was initiated by the governors of Wyoming and Utah in September 2003 as a follow-on to the SEAMS Steering Group – Western Interconnection (SSG-WI), a west-wide transmission expansion planning effort. The study analyzes greater use of existing transmission assets as an alternative to physical upgrades or new transmission construction.

As part of the earlier SSG-WI work, Dean Perry of the Northwest Power Planning Council studied most of the major transmission paths in the western interconnection and found that most of the paths are constrained only a few hours per year. That finding notwithstanding, no additional transmission capacity is available on most of those major paths. All of the long-term firm transmission is reserved under contract, but, in fact, it appears that a large number of hours per year exist in which thousands of megawatts could be transmitted around the system.

To explore this issue of unused capacity in more depth, RMATS has a tariff and regulatory issues workgroup~~,~~ which is undertaking a case study of three particular constrained paths in the Rocky Mountain region that are all very important inter-regionally in the West. With the assistance of a U.S. Department of Energy contract through the National Renewable Energy Laboratory, RMATS is analyzing Western Electricity Coordinating Council (WECC) data, looking at the actual physical flows on these three constrained paths and matching them against wind power output. Wind is used as the leading example of new resources being added to the system. As an intermittent resource, it has more capability to accept some curtailment.

The hours of the highest constraint on these paths are actually also the hours of the lowest wind output, which may mean that wind projects would suffer very little economic penalty from being curtailed to be able to utilize the physical transmission capability that exists.

This finding could be important for the timing of transmission alternatives. If RMATS concludes that in the Rocky Mountains thousands of megawatts of existing transmission capacity exist that could be used, for example, by wind projects, then this practice could be implemented years quicker than new physical upgrades could be permitted and built. So, in the very near term, over the next two to eight years, it might be possible to connect a significant amount of wind and other new resources to the existing system.

Adding renewable resources to utilize the existing grid could also defer investment in new physical upgrades with reduced attendant public costs and increased environmental benefits. In addition, transmission revenue to transmission owners could rise, if mechanisms are available that would allow the owners to increase the use of their lines.

PacifiCorp is interested in this idea from an incremental transmission revenue point of view. The Bonneville Power Administration (BPA) also has a project to recalculate available transmission capacity (ATC) specifically toward these goals.

One of the key mechanisms that the RMATS is looking at, and that would be necessary to take advantage of existing transmission capacity, is a new tariff or an amended tariff. Right now long-term, firm and non-firm service tariffs are available. If a transmission line is constrained at all, then having firm transmission service across that path is not possible.

In response, the American Wind Energy Association has developed what it calls a flexible firm tariff, or a curtailable firm tariff, in which the number of hours of curtailment is limited contractually and is set at some level appropriate for that path. This kind of certainty would enable wind power developers using this flexible firm or curtailable firm tariff to get their projects financed and still be able to use that transmission.

Mr. Olson expects the report to be published by the end of July 2004. He urged that the results of RMATS be kept in mind as an alternative to new transmission construction.

Steven Kelly, Independent Energy Producers Association (IEP)

Alternatives should be considered at all times during transmission planning and siting, not just at a discrete point. Many of the issues discussed at the workshop, such as how to integrate transmission planning into the energy environment in California and the West, are issues that were raised a number of years ago and planners have been struggling with them for some time. Most of the problems stem from the fact that the available generation in the inter-regional West is subject to the jurisdiction of multiple and disbursed authorities, cutting across state and federal agencies and so forth.

Something needs to be developed similar to the interagency Energy Action Plan, which lays out a vision of how, in California, and hopefully the Western region, to move forward and plan transmission.

Planning needs to occur in three contexts:

- Consider economic and reliability projects on a long-term basis that is integrated with corridor planning.

- Consider short-term projects to deal with the one- to five-year issues that arise and are needed for reliability before new transmission lines can be built. Building and scheduling generation and planning for transmission to meet reliability needs can be planned on a long-term basis, but a process and mechanism is needed now that allows adaptation of long-term plans to meet contingencies such as under-scheduling or infeasible schedules being followed at the CA ISO that increase transmission congestion rather than mitigate it.

- Deal with the Renewable Portfolio Standard (RPS) buildout, which is somewhat different than economic or reliability buildout. It is not clear how the state-mandated preference to develop renewable generation resources will be integrated into transmission plans that are focused on economic or reliability buildout, but it needs to be taken into consideration. It should be noted that Senate Bill 1078 (SB 1078, Sher, Chapter 516, Statutes of 2002) requires that the Energy Commission and the CPUC work collaboratively to implement the RPS and assigns specific roles to each agency.

The transmission planning process should be more transparent. As close as he is to transmission planning, he still is confused about actual plans and how some of them play out, *e.g.,* how the computer models are operated, and over what timeframes etc. It is even more troubling for someone who is further from the process than he is to try to understand.

Right now at the CPUC, a debate is going on about the transparency of the CA ISO's transmission planning process, because the CA ISO has vendor agreements that are proprietary and limits their distribution. We need to figure out a way to work through this problem so that more parties can get access to the actual transmission data, as well as the information in the IEPR, and the utilities' long-term generation procurement plans.

It is only through transparency that all the planning components will fit together and meld. Hopefully this transparency will allow stakeholders and policymakers to get involved and to agree on the need for infrastructure and generation development and investment.

Mark Ward, Los Angeles Department of Water and Power (LADWP)

Mr. Ward agreed with Steven Kelly that alternatives to transmission should be part of the planning process right up front when considering new resources to serve load, whether local or regional.

In 2000, LADWP approved its *Integrated Resource Plan* for the City of Los Angeles. Part of the plan was to provide one-half of the City's load growth on an annual basis with renewable resources. As part of the plan, marginal transmission costs are considered early when deciding where the resources can be located in an economically justifiable manner to serve load~~s~~.

As a result, Los Angeles has generally given first consideration to local generation resources, *e.g.,* it accepted a bioconversion park that is currently being developed and is expected to be online in the 2008 to 2009 timeframe. The facility will be located inside the city limits. In addition, LADWP has also looked at a new windfarm in the Mojave area which would further utilize some of Los Angeles's existing transmission assets.

Thus, LADWP focused on using its transmission assets and their existing infrastructure more fully, and minimizing transmission line construction. However, in the 2009-2012 timeframe, the City, along with the rest of the state, must look at where the future generation resources are actually going to be. The state and the City have been experiencing load growth in the 1.5 to 2 percent range over the last several years. For the state, that means 500 to 1,000 MW annually; for the City of Los Angeles it is about 60 to 80 MW annually. Therefore, LADWP supports the Commission in identifying transmission corridors.

Morteza Sabet, Western Area Power Administration (Western)

Mr. Sabet disagreed with some of the earlier statements and thought that there was nothing wrong with the current process for transmission planning, except that there was is too much "dead weight" in the existing planning process and discussions.

In the 1970s there were fewer "players" and the Energy Commission could direct the utilities to look at alternatives. Even then, if a project did not make economic sense it was not built. Today, no one entity has that much control over transmission planning.

If a project is real then it will be considered in transmission planning, including distributed technology, demand-side management, centralized or decentralized generating stations, small- or large-scale projects and regardless of who is involved.

Planning cannot be done any other way; the process is working. Instead, the institutional overhead should be reduced.

Chifong Thomas, Pacific Gas and Electric (PG&E)

Before thinking about alternatives to transmission reinforcement, know what problem needs to be solved. For example, when looking at a severe overload, voltage collapse problem, or loss of a transmission or generation facility and trying to replace that with a generator, consider that any replacement generator must run during all those times, in anticipation of the loss of the facility.

Generation needs to be matched to the load at every instant. Otherwise, problems would arise, such as over-frequency, under-frequency, and cascading.

Due to the length of time it takes to plan a transmission line, integrated planning should not increase the lead time when including other alternatives. She agreed with Mr. Perez that alternatives should be included in cost recovery as well as the cost of siting a transmission project. Otherwise it is more difficult to figure out how to do integrated planning.

As far as the current process is concerned, Ms. Thomas agreed with Morteza Sabet, that planning is pretty much an “open book” because the CA ISO and PG&E have stakeholder meetings and base-case assumptions are agreed upon with the stakeholders. PG&E lays out the assessments, including the programs that uses, which are commercial packages available at General Electric, PTI, or any other vendor. Also the data can be obtained from WECC. PG&E regularly discusses problems and assessments in WECC and is under CA ISO's purview.

Presiding Member Geesman disagreed with Mr. Sabet and Ms. Thomas’s comments and cited the Mission - Miguel 230 kV #2 Project. Commissioner Geesman said that it was known with some degree of lead-time that 1,660 megawatts were coming online in the summer of 2003. In the fall of 2001, the parties stipulated to the economics of the project, and agreed that it was justified. In spring 2002, the CA ISO Board approved the project and SDG&E subsequently filed an application for a CPCN. After that filing, no action occurred at the CPUC for 14 months. Therefore, somewhere between all of the different institutions involved in this, he felt that one ended up with a pretty abrupt sense of failure. Congestion costs are being incurred at the Miguel substation on the order of $3 million to $4 million per month. It does not take very many months to erase the $31-million cost of the project in terms of foregone economic generation.

The Energy Commission staff revised its forecast during June 2004 for this summer’s prospects and anticipated that a problem in meeting the supply/demand balances could occur this summer, and quite likely the failure to approve these upgrades will play a fundamental role in that problem. Therefore, Commissioner Geesman did not think the current process for planning and permitting for transmission upgrades works because if it did then the attendance at these workshops would not be as high.

Commissioner Geesman had referred to more of a regulatory implementation and permitting issue with the Mission - Miguel example than a planning issue, because decision makers in the planning process did not question whether Mission - Miguel was needed. Therefore, it was a correct decision and the planners cannot be blamed for the problems.

Maury Kruth, Transmission Agency of Northern California (TANC)

TANC is a majority owner of one of the intertie lines, which is jointly operated with Western. TANC has also worked a great deal with PG&E. Mr. Kruth agreed with part of Ms. Thomas's comments, but Mr. Kruth also agreed with Commissioner Geesman. He thinks the planners generally do quite well working with each other in various forums, but actually building transmission is where the real problem lies. For instance, the Path 15 upgrade should not have taken as long as it did.

In addition to renewables, distributed generation, and conservation, the municipal utilities see transmission as a very important part of an overall portfolio. Transmission can be complementary to those things in a resource plan. It can be used to deliver wind and to cover problems in the system.

Typically, the transmission of power on the intertie to the Northwest works in both directions. When California has surplus generation in the winter, on occasion, California can sell power to the Northwest. California can do things with the Northwest and with the system in Canada that really add value to California. So, Mr. Kruth would encourage the Energy Commission continue to consider transmission even though it is very difficult because robust infrastructure is important. It ought not be viewed as an "either/or -- just transmission or just renewables" situation -- because both are necessary.

Dan Ozenne, San Diego Gas and Electric (SDG&E)

Mr. Ozenne seconded Commissioner Geesman on the Mission - Miguel 230 kV #2 Project in San Diego. Mr. Ozenne also touched on some of the alternatives to Mr. Kruth's comments by saying that SDG&E has been following the loading order established in the *Energy Action Plan* and has really embraced it in its long-term resource planning. This loading order requires consideration of all of the alternatives that were discussed in the workshop besides generation and transmission. So, the priorities of energy efficiency and renewables and so on are built into SDG&E's long-term planning. Therefore, these alternatives are considered early on in planning and are given ample opportunity for consideration.

SDG&E believes that the question should not be either alternatives *or* transmission, but both, because both are critically needed. The San Diego area has a growing population and loads and some of which could be met with low-cost resources in SDG&E's service territory. However, SDG&E also needs access to resources beyond its service territory. As Commissioner Geesman pointed out, the failure to come to grips with the transmission problems at Miguel is costing, according to the CA ISO estimate for first quarter this year, $15 billion to San Diego customers. In addition, more inefficient polluting plants are being dispatched to make up the difference. So, resources are being burned that are not necessary, at a cost that is higher than necessary, and with increased pollution. Mr. Ozenne thinks the need for additional transmission must be dealt with today.

Mr. Ozenne added that Steven Kelly (IEP) mentioned that the EAP was a good plan for resources, but did not say much about transmission. Mr. Ozenne thinks that more is needed in terms of making sure that transmission is available, including anticipating the needs of the future, identifying and preserving transmission corridors, and developing a reasonable and timely permitting process to ensure availability.

In the meantime, SDG&E is aggressively pursuing local alternatives, energy efficiency, and demand-response opportunities. SDG&E will shortly send out a request for proposals for renewable energy resources to meet the SDG&E RPS targets. It is likely that the utility will not be able to meet this objective without new high voltage transmission capable of bringing wind and geothermal into its service area.

Unfortunately, San Diego is located in an area without a tremendous opportunity for additional renewables. During SDG&E's last renewable solicitation, it contracted with every proposed project that was located within San Diego County and that met the market referent price. SDG&E will continue to seek out local renewable options, but it is clear that a good deal of renewable resource imports are necessary to meet the goals.

In addition to these outreach efforts for renewables, SDG&E is pioneering the development of distributed generation within its service territory through the "Sustainable Communities" projects. These projects feature the integration of renewable generation and fuel cells at the distribution system level. In the Mar Vista project near downtown San Diego, SDG&E has worked with the developer on a redevelopment project that will include solar photovoltaics (PV), an onsite fuel cell in a mixed use subdivision. In another project, SDG&E is working with a commercial tenant to include PV, fuel cell and advanced building design features in the redesign of existing commercial space. SDG&E will continue to innovate with different developers and customers to explore new ways to integrate local power generation with the distribution grid.

In sum, Mr. Ozenne believes it is not "either/or," but "both," because transmission needs are real and immediate. SDG&E is concerned that as early as 2006 reliability can become a major issue in San Diego unless action is taken very quickly to relieve transmission congestion problems. Unnecessary energy costs are already imposed on its customers due to the inadequate transmission. California must immediately confront its apparent unwillingness to expeditiously site and approve transmission projects necessary to meet reliability, least-cost and renewable-generation objectives.

Patricia Arons, Southern California Edison (SCE)

Ms. Arons views transmission as a societal choice, not just a transmission planner's tool. It is a difficult decision to build transmission, and it is necessary to have a company that is fully committed to do so; a regulator that is fully committed and behind the decision; and processes that have been adequately attentive to the issue of alternatives.

How to go about considering alternatives is the critical question, and Ms. Arons thinks that an understanding of what transmission is as a solution is critical. If planners think in terms of “appropriate technology” precepts, then “appropriate technology” says there is an appropriate technological solution in terms of consumption of natural resources, capital, and human time. She thinks that it has been recently shown in California that transmission has become an inappropriate technology solution because of all of the problems and holdups and “analysis paralysis” that has resulted in transmission projects not being built.

Ms. Arons is concerned that if transmission is considered as an option for the future, in terms of how to serve load and society’s needs, then planners need to think through how to go about making the decision. She agreed that the process is not as effective as it could be and it is very time consuming. She also admitted that she does not have all the answers in terms of how to make it perfect. With the permitting process, the construction time, and the decision-making time, transmission is an undertaking with a long lead time.

In the course of a permit application, if one also tries to consider alternatives~~,~~ such as DSM, Ms. Arons is concerned that these considerations could result in “analysis paralysis.” Options like DSM and renewable generation are initiatives and decisions that have to be made early on in terms of society’s commitments to those particular technology solutions. The CPUC’s order, as described by Barbara Hale (CPUC), is effective in ensuring consideration of DSM, renewable energy development, and others before the question of transmission alternatives is raised.

Transmission is driven really by one thing, and that is the load growth impact on the performance of the power grid. Society’s decisions on DG, DSM, and so forth should be built into growth forecasts. In order to count on an alternative, its effectiveness and success must be certain. Generation cannot be relied on if the retirements in the CA ISO-controlled grid and shutdown decisions are based solely upon the financial situation of the owner of that asset. So, continued reliance on a solution that might have a short-lived effectiveness is, in essence, just postponing the decision to build transmission.

Ms. Arons disagreed with Greg Karras (Communities for a Better Environment, CBE) and his views about re-engineering the grid to interconnect distributed generation resources, which he discussed in his presentation and later during the panel discussion (see below). She did not understand his earlier statement, which she believed was a policy problem. In her view, protocols for interconnecting generation are very well established and exercised every day by numerous entities looking at the potential for interconnection. SCE goes through those studies at the transmission and distribution levels, in her view, very effectively. Complaints about generation interconnection have not come up in quite awhile at FERC. The underlying question is whether a subsidy is necessary to get distributed generation off the ground, which is a wholly different question that does not have anything to do with how the grid is engineered.

Ms. Arons complimented Mr. Smeloff and the San Francisco Public Utilities Commission on a great job in making societal types of choices as alternatives to transmission. However, because of security concerns, Ms. Arons did not approve of Mr. Smeloff for publicly revealing a circuit diagram and including it in a presentation that is going to be posted on the Internet.

Armando Perez, California Independent System Operator (CA ISO)

The entire grid needs to be considered in planning, because transmission is not the only solution to the problem and in some cases it is not the best solution to the problem. The goal of the CA ISO is to maintain reliability of the grid, which is measured against NERC, WECC, and the CA ISO’s standards.

CA ISO plans and expands the grid to insure reliable and efficient transmission. The CA ISO cannot do anything about generation, demand-side efficiency, or a combination the two. California needs a way to fix the statement that “the only solution for a transmission planner is transmission.”

Mr. Perez discussed the Tri-Valley Project. The CA ISO had identified a preferred transmission project, and it decided to try a pilot project to determine if an alternative could be implemented which would eliminate or defer the transmission project. The CA ISO solicited proposals from generation developers on load-based alternatives, and got four responses for a total of 264 MW of generation and approximately 30 MW of demand response. The alternatives were analyzed and the generation and load management proposals achieved the goal of eliminating the overloads and the voltage problems for five years. However, the savings from deferring the transmission project for five years did not justify the cost of the additional generation or the load-management proposal, and the transmission project was chosen as least-cost solution.

Mr. Perez questioned how one should evaluate transmission, which is a different "product" than generation. If generation is "off" then power is not produced. However, it is unlikely that a transmission line will be out of service for any length of time, and other generation resources are available. An appropriate comparison is difficult.

State agencies and the CA ISO need to work together to integrate state planning and procurement proceedings with CA ISO's grid planning process. There are ways of possibly recovering the costs with this generation. Mr. Perez thinks the objective of this process to consider all the costs and benefits in the proper light. Planners then need to make sure that the right project is brought back to the ratepayers — the one that makes the most economic sense.

Mr. Perez asked Greg Karras (CBE) what he meant by redesigning the grid. Because if, in fact, distributed generation and demand-side practices serve load, the CA ISO would see a load equalization or a load reduction. Thus, at some point in time the CA ISO would be less likely to need additional grid expansions.

Mr. Perez was intrigued by Mr. Steven Kelly's (IEP) statement that more transparency is needed in transmission planning, and he asked Mr. Kelly what else was needed.

Mr. Kelly thought that he put things in more of a political context, because if the lack of transmission infrastructure is not stemming from the engineers and planning assistant at the bottom of the tier, it is stemming from the problems that occur in the political context where people are not convinced of a need for the project, or they have convinced policymakers that they have a way to litigate against the project. He was talking about a transparent process so that when the CPUC, the Energy Commission or whoever says that they have looked at the alternatives and they believe that a project is the best alternative, it should go forward. Then the other agencies are relatively quiet on it, and it is harder for people to litigate to stop it. There is that kind of comfort in the planning process. He was not talking about all the engineers, the 15 or 25 in the state that actually might know what is going on, that are plugging modeling and inputs in and out. He was talking about a higher level of transparency.

There is a problem with generation. For example, the Otay Mesa project was approved last week. However, only the connecting line between the station and the grid was approved. So now there is another plant that is not going to be deliverable until something else happens, because it is going into the wrong area of the system. These kinds of decisions keep being made, and then people ask later about why so much money is spent.

Mr. Perez agreed with Ms. Arons concerning response to society's choices. Society decided to build a plant in Mexico for whatever reason and there are some economic advantages created by that plant being there. At the same time, 4,000 or 5,000 MW of generation has been added outside of Phoenix. The entire load of the state is about 4,000 or 5,000 MW so there has to be a lot of generation that is looking for a place to go, *i.e.,* California. The CA ISO is responding to the economic opportunities wherever they are. It will continue to look at what is the best. Mr. Perez concluded that the question is do we want 4,000 or 5,000 MW in Arizona or 4,000 MW here? Do we build a transmission line? Those are the challenges that he has to deal with every day.

Barbara Hale, California Public Utilities Commission (CPUC)

Ms. Hale discussed how the CPUC was working towards integrating the investor-owned utilities' (IOUs) efforts at resource procurement. The CPUC's focus is not just generation, DG, other kinds of resources and transmission, but the broader effort of planning how to provide California with reliable electric service in the most cost-effective and environmentally-sensitive way.

The EAP says that California should pursue all cost-effective energy efficiency first, all demand response that is cost effective, and move down the list to distributed generation, renewable generation, fossil generation. And simultaneous to pursuing those different resources, the State should also pursue all needed transmission upgrades. The CPUC, since May 2003, has been implementing that broad policy statement via a number of proceedings.

Ms. Hale recognized that the Energy Commission has a broader statewide perspective; the CPUC is only responsible for the IOUs. The CPUC also recognizes that local reliability is a more granular look at the system and is a very important part of determining what the current system needs. Therefore, in addition to an IOU service territory-wide look, a more granular look at the local reliability level is necessary. What comes to the CPUC this year in procurement plans is going to affect resource planning for many years into the future.

The CPUC is working with the CA ISO on streamlining the CPUC's permitting process. During the permitting process the CPUC identifies whether a project is needed; what its total cost is; and whether it meets the California Environmental Quality Act (CEQA) requirements. The CPUC recognizes that the permitting process needs to be streamlined to get needed resources constructed in a timely way and to avoid any duplication of effort among state agencies. The CA ISO has recently filed an economic methodology that the CPUC will evaluate. The CPUC hopes to agree with the CA ISO on an appropriate method for assessing the need for transmission projects in the State. If this effort succeeds, the CPUC won't need to repeat the CA ISO's need evaluation every time that the IOUs bring forward a proposal.

The CPUC also adopted an order that directed further study on the Tehachapi corridor to bring renewable resources into the load centers. The CPUC specifically directed SCE to file a CPCN for the early phase~~s~~ of such a project within six months.

Commissioner Geesman asked whether Tehachapi would fall into the CA ISO reliability or economic category of transmission upgrades. He asked if Ms. Hale saw this as a third type of transmission project, and if so, how would she propose that the State evaluate it.

Ms. Hale saw the Tehachapi project as a third type because the Legislature directed the CPUC by new law to bring renewable resources into the load centers in California. It is seen as a different effort and the analysis and criteria for whether a project should go forward are going to need to take into account that new law. The CPCN that SCE brings in will begin to shape that. Ms. Hale thinks that through the RPS docket and the transmission planning docket the CPUC is giving the utilities some direction on assessing the costs and on who pays, which is going to have an influence on the need for and economic evaluation of the project.

The bottom line is that the CPUC has been directed to increase the state's reliance on renewable resources. The Energy Commission, very helpfully, pursuant to the law, put together an assessment of where those renewable resources are located in California. Many of them are in remote locations, which puts a lot of pressure on building new transmission infrastructure to bring those resources to load. The CPUC is trying to break new ground and look at a new way of assessing these projects.

Commissioner Boyd appreciated Ms. Hale's recognition that the CPUC is dealing just with the IOUs and so mutually, through the EAP and other devices, there is a collective need to look at the broader picture. There are many issues, so it is going to take all the agencies who are working together here and who expressed an interest in the various pieces for which they are responsible to integrate these issues.

Ms. Hale commended Armando Perez and the CA ISO for its staff report, attached to the CPUC transmission permit streamlining OIR, where this problem of transmission "chasing" generation is discussed. Merchant generators have economic incentives to place plants where it makes sense for them, rather than where the placement would make sense for the grid, or for load there are some market design changes and some permit streamlining changes at the CA ISO and the CPUC that will help. But as the system becomes disaggregated, the City and County of San Francisco, and perhaps other entities, are going to embark upon community choice aggregation programs which will result in another group of interests operating outside the familiar venues. If this does occur in San Francisco, a large group of PG&E customers will have a different venue at which to demonstrate load and need. This new venue will have to be integrated somehow into the actual system that the CA ISO is challenged with operating on a daily basis.

The "how" to discuss alternatives to transmission is through an integrated, iterative process. It should include the balancing of a portfolio of resources and an iterative way of looking at what the resource options are and what makes sense, given the public policy pronouncements from Sacramento and from within the various state agencies, like in the EAP. “Where” to have this discussion is at the decision-making authority's designated venue where the regulatory authority lies. That is where planners need to look at making the final decision regarding in which resource alternatives they invest.

Determining “W*hen”* the alternatives should be assessed should be a two-step process — during planning and during permitting. This can occur prior to permitting at the CPUC and prior to any permitting the CPUC is looking at through the procurement proceeding for all the resource options. The CPUC looks expansively at alternatives in a planning forum prior to permitting. If planners have looked at the broader issues and choices and overlaid the societal preferences that are expressed by lawmakers and the EAP, then this broad consideration should happen in the planning stage. Then, during the CEQA process, when a specific project and need are being addressed, there should be a more narrow alternatives analysis.

The IEPR is a very broad and constructive effort of the Energy Commission that aids entities like the CPUC, the IOUs, and the publicly-owned utilities in looking at resource planning and procurement options, including retirements. The CPUC also relies on the Energy Commission’s demand forecast as the base case for the IOU’s assessments of their needs.

Anticipating resource needs and conducting focused studies like corridor planning, liquefied natural gas (LNG) prospects, and defining the public interest in LNG are also helpful. Looking at renewable resource availability as the Energy Commission did pursuant to the RPS statutes, and the impact of intermittent resource development on grid reliability, are areas the Energy Commission can pursue in the IEPR that would be very constructive for all of the entities who have to make some of these investment decisions. She encouraged the Energy Commission to look at its IEPR authority in its statewide role, try to bring more interests together, and try to focus on all of the load-serving entities' responsibilities. Ultimately everyone is going to need to work together to have the systems maintain reliability, because California has disaggregated load and supply options and responsible authorities.

Ed Smeloff, San Francisco Public Utilities Commission (SFPUC)

Mr. Smeloff gave a local area perspective on planning for alternatives for transmission projects from the context of the City and County of San Francisco. He discussed what would be necessary in San Francisco to improve the process of evaluating whether distributed resources can act as a realistic alternative to transmission. This process would mean looking forward to what projects would be needed over the next five- to ten-years, developing capital budgets for those projects, and having a better understanding of both the timing and costs of transmission projects that would be proposed.

More fine-grained information is necessary on loads by class and by small geographical areas and on the growth rates that are likely to occur within those groupings of electrical load. This information would allow the SFPUC to better compare the ability of DG and DSM projects to defer or eliminate the need for transmission projects. A mechanism to identify and prioritize DG projects would also be necessary, rather than the current situation, which is somewhat sporadic in terms of proposed DG projects and based on the ability of developers to market those projects in the interests of specific property owners within an area like San Francisco or the Bay Area.

Greater certainty about cost recovery for the value of the grid enhancements that these projects would trigger is also necessary. Right now the planning is simply done on the value of the energy that projects bring to the property owner. Similarly, planners need to target DSM programs that are funded by the public goods charge and other mechanisms by area and by time. An integrated marginal cost approach is important to determining the value of DG and DSM. The marginal cost of local transmission and distribution projects that might be deferred by a DG or DSM portfolio needs to be combined with the marginal energy costs and the capacity costs of the energy portion of the DG or DSM project.

Though it may be different region-wide, in a small area such as San Francisco, the SFPUC needs to make sure that the projects provide the resource, the electricity and the relief from transmission congestion when needed by the system. SFPUC has established a precedent for some regional planning in San Francisco and the Peninsula. The CA ISO and PG&E have been very cooperative. The CA ISO is now hosting a Phase Two for a Peninsula transmission study that the CA ISO is hosting.

It would be helpful if utilities were required to engage in least-cost transmission and distribution planning for small geographic areas. A regional collaborative would take responsibility for working with the utility to determine the avoided costs for transmission and distribution, to identify potential DSM and DG alternatives, and then to recommend an implementation plan that allowed for cost recovery of alternatives to transmission projects.

The San Francisco Bay Area would be an excellent location for such a collaborative process, building on the processes that the SFPUC has already developed, but applying it regionally to look at proposed transmission projects, and to compare them to potential new generation projects, DG projects, and retiring some of the other older units within the Bay Area.

Commissioner Geesman asked how far the existing DG or transmission planning processes are from what Mr. Smeloff characterized as a least-cost planning process.

Mr. Smeloff thinks that California is still quite a ways away from having a process that fully evaluates both the technical and economic potential for DG and compares it on an equivalent basis with transmission alternatives. In the Bay Area, there is interest in doing this. PG&E has been engaged in a community-participation process for the last two years and could provide some more fine-grained analysis. The analysis needs to be taken down to the distribution level as well. However, planners are still a significant way from being able to effectively compare DG and DSM to transmission alternatives.

Mr. Smeloff further commented on the interconnection of DG. While some rules are clear, such as CPUC Rule 21 for connecting DG to radial feeders, other rules are far from clear, and the experience of developers in San Francisco has been that it is very complicated to connect to the network. During the Moscone project, which is a 670 kV solar project connected to the transmission system, it was not revealed to the SFPUC what the additional costs for system protection were until they were well into that project. So there is a need for more transparency and clearer rules related to interconnection.

Mr. Smeloff also discussed the balancing between security and transparency in public participation. In planning for the system in San Francisco, the SFPUC has had a very intense community stakeholder process that involved the CA ISO and PG&E and included some detailed power flow analysis. And it was only through that kind of analysis with community involvement that very specific projects came up, e.g., the need for additional reinforcement of the internal 115 kV system in San Francisco that Mr. Karras mentioned.

The choice of those alternatives could only be done by revealing to participants how the system is designed. Operational details, such as looking at how the system clearances are done in one of the substations in San Mateo, needed to be discussed publicly so that alternatives can be understood by the public. Therefore, there is a balance. Mr. Smeloff agreed with Ms. Arons that detailed information should remain out of the public domain, but that it must be balanced with a need to work with the public to adequately evaluate alternatives.

Timing is really crucial in viewing alternatives. The permitting process is too late to adequately consider the smaller-scale resources, DG, and DSM, which require many actors to implement them. As in the case of the Jefferson - Martin 230 kV Transmission Project, that was really not an appropriate time to think of very aggressive efforts towards energy efficiency or DSM.

Having an advance public participation process that looks at alternatives can result in more support and certainty. Once a transmission project is agreed to, it will get through the permit process and be built. Look at the potential DG and DSM alternatives far in advance, possibly five years. This advanced look corresponds to understanding load growth and specific locations, down to the distribution lines, where load growth is going to occur.

New planning tools and new ways of analyzing alternatives are needed to aid the process, but planners also need to think pretty far in advance when looking at alternatives to not delay those transmission projects that turn out to be genuinely needed and need public support.

Greg Karras, Communities for a Better Environment (CBE)

Planners need to re-engineer the grid to “plug in” what needs to be “plugged in,” instead of what planners need to be getting rid of. He displayed a quotation from the Journal of Science that said, “Advanced electrical grids would foster renewables. Existing grids could [sic] not manage the loads. Present hub-and-spoke networks were designed for central power plants. Such networks need to be re-engineered.” Therefore a decision to add to the existing system is a choice about the energy future. In addition, some of the costs of choosing to build onto the existing system will worsen in the future.

From the perspective of transitioning to sustainable energy, building big “wires” and big “chunks” that then “plug-in” central generation in big chunks, instead of small wires, or another system that works better for DG will further undermine the reliability advantage of the distributed renewable technologies. A DG system with renewables is more reliable, because the biggest single piece that could go down is much smaller than a big power line or a big power plant where an outage would result in the loss of hundreds of megawatts at a time. A “small wires” system would require much less backup and would cost much less to build.

However, if the old system continues to be expanded then that advantage is taken away in the short term because whatever resource is put in place, whether renewable, DG, or power plants, still needs to backup for the biggest part of the system that could fail. Under existing reliability criteria, this level of backup includes big power lines as well as big power plants. So by building onto the old system planners actively make choices that discourage the ramp-up of DG and renewables. Also, continuing to build big blocks of “big wire” capacity instead of building the “small wire” capacity more incrementally actually increases future load and demand.

Unsustainable energy is not reliable in the long term. In addition, the costs of the old energy regime may increase sufficiently to erode our ability to make the switch. This may happen within the timeframe of the infrastructure that is being built now. So, it is only prudent to look at the alternative of rebuilding the grid now, re-engineering it so that it actually works to “plug in” the new generation technologies, and not the transmission and generation that should be phased out. Based on the time scales for these investments and how long this “stuff” gets hard-wired once it is built, Mr. Karras strongly recommended that this change be part of the integrated plan, if not the centerpiece of the transmission portion of it.

Based on experience he believes that it is important to follow the local communities' advice. In San Francisco there has been a lot of progress in that direction, but there is also a long way to go there. This is the matter of environmental justice, and about political feasibility.

In the short term, the re-design of the grid needs to give priority to connecting renewable resources using the existing system or something like it. He did not know if this would be an advanced-DC line that is more efficient or if it would mean assigning priority over the existing lines with a few twists and turns. But he thinks that should be part of the design, because the system has to evolve.

Alternatives should be assessed in workshops similar to the current one~~,~~ because people had listened to him and others had raised some further issues for him to think about. People cannot necessarily control the creative process or the way technology moves, but when a good idea comes up, planners should look at it. He encouraged everyone at the workshop to think of the bigger picture.

Mr. Karras suggested that planners and agencies should come to the affected communities and tailor the process to them. From the communities' perspective the reason why projects get delayed is the communities do not know what is going on, or feel that the facts have been hidden. The way to fix that perception is largely by answering the "where" question -- by doing it with the community that is most impacted.

Fred Mobasheri, Electric Power Group (follow-up comments)

Electric Power Group has done three studies for the Energy Commission. The first one was on the value of transmission, which showed that almost all of the transmission that has been built in California was cost effective and has brought many benefits.

He wondered when these alternative evaluations would occur. Ms. Hale suggested that the long-term procurement process would include these alternatives evaluations. Mr. Mobasheri's concern was that the procurement process evaluation would be at most five to ten years, which is not long term. The emphasis for the utilities is going to be on the next resource or transmission project it wants to build. Most transmission takes ten to 20 years to build, which requires looking at the very long term. He doubted that the procurement planning at the CPUC will address the strategic questions. If planners are really looking at strategic questions, such as corridors and land acquisitions, he did not think the long-term resource planning would answer those types of questions.

As a result, strategic planning is necessary. Strategic planning is not being done now, has not been done in the long-term planning process, and it is not done when looking at specific projects. This planning could be performed by the CPUC, the Energy Commission, or perhaps the CA ISO. The problem with CA ISO is that it would look at only transmission, not the other alternatives. And so perhaps the Energy Commission should be really looking at the strategic questions that nobody at the present time is considering.

Commissioner Boyd, Associate Member (follow-up comments)

Commissioner Boyd agreed with Mr. Mobasheri's concerns about broader long-term strategic planning.

Commissioner Boyd then referred to the San Francisco regional planning effort that Ms. Hale discussed and wondered why another planning effort on a micro-scale rather than on a macro-scale is needed. A "micro" planning effort would have an underlying inability to address all the relevant aspects, including local land use planning, as well as a broad enough time horizon, as would be done in a strategic planning effort. At the same time, Commissioner Boyd has come to accept (and even almost look forward to) the contribution of some of the local efforts that are going on because he has hope that they will look at more of the issues than have been looked at previously.

Some entities are under charter, under legislative mandate to look at certain pieces of the puzzle. Now, the need to look at a broader picture has been recognized. He hopes that all these puzzle pieces will come together some day so the situation can be salvaged before there are 50 million people in California and no ability to put anything anywhere because everything would be in somebody's back yard, literally. This is why some long-range planning is necessary.

Ms. Hale responded saying that she did not mean to suggest that the effort of, for example the City and County of San Francisco, is a bad thing, but rather it is a reality that there will be additional load-serving entities. Even though LADWP and TANC spoke, the focus of the workshop was largely about what the IOUs are doing with transmission and how the CPUC can integrate it. The list of load-serving entities is going to grow because the law was written for community-choice aggregation, at the efforts at implementing a core/noncore program, so it is going to get more challenging to do the kind of strategic planning that is being discussed here.

Regarding Mr. Mobasheri's comments, Ms. Hale did not think the CPUC disagreed. She sees the IOUs' long-term plans as being 20-year plans. The actual investments will meet near-term, five- to ten-year, needs. Ms. Hale intended to call out where she thought the Energy Commission could add real value, which is on longer-term strategic planning issues like corridor right-of-way issues, and corridor planning to leverage each agency's authority and expertise to address these issues.

Patricia Arons, Southern California Edison (follow-up comments)

There is a real opportunity within the existing law for the State to make some headway in terms of corridor planning, and what it can mean for the long term.

Initially the study proposals focus on the Southern California region and transmission lines necessary to interconnect renewable generation. Take one renewable area, such as Tehachapi, and focus on that area instead of trying to do all of Southern

California; therefore the focus should be on renewable energy projects and on one area in particular, and the study should explore the meaning of corridor planning within that context.

Steven Kelly, IEP (follow-up comments)

Mr. Kelly asked what steps would be recommended for siting a transmission project versus planning one.

Commissioner Geesman responded by saying that the premise is through a Programmatic Environmental Impact Report (EIR) one can address some of these issues early on and avoid having everything become an issue in the permitting stage, or the final permitting stage of the project. Focusing on the provisions of GO 131-D would be constructive under the current law, which should be changed. In keeping with the theme of corridor planning, if planners can segment some of these large 50-year societal choices into smaller more digestible pieces, and get the early ones addressed in a planning process, arguably they can make the permitting stage of the process go more smoothly and with more predictable results.

Mr. Kelly then asked if the real decision is not how, but whether to do a Programmatic EIR.

Commissioner Geesman responded by saying that he thinks that there is a “how to” aspect of the decision because a process is necessary that will carry out the planning intent of CEQA and will adequately balance the priorities expressed in CEQA, which is supportable by the local public that will be most directly affected, as well as by the general public that the Energy Commission serves. There are some complicated legal aspects to make certain that subsequent government decisions would be justified in relying on that Programmatic EIR without triggering, as we have seen so often in the CPCN process, the need to relitigate everything again and again.

Mr. Kelly reiterated his prior comments on the need for a mechanism to make the decision process more transparent. He concluded that a Programmatic EIR sounded like one tool to get there.

Anjali Sheffrin, CA ISO (follow-up comments)

Dr. Sheffrin added that she thinks that when looking at transmission planning, generation interconnection also needs to be considered. She cited Otay Mesa as an example of where the plant gets permitted, but the question is not asked, “How is the generation deliverable to load?” It gets picked up in the CPUC procurement process and then all of a sudden something is being added. And it comes to the CA ISO and it is not deliverable. So, Dr. Sheffrin suggested that generation interconnection be looked at as a more comprehensive issue.

Commissioner Geesman agreed with Dr. Sheffrin that the Otay Mesa situation is the unintended consequence of the arbitrary division, which State government made 30 years ago, when it separated generation from transmission. He thinks there are too many different governmental entities are looking at similar questions and these are expensive consequences to deal with.

Summary of Written Comments

Following the June 14, 2004 workshop, the Energy Commission staff requested follow-up comments and feedback from interested parties by June 25, 2004 on the following topics:

- Does the vision statement and its elements provide the proper guidance to policymakers in choosing the future direction of California's transmission system?
- Is it complete? Are there other elements that should be considered?
- Should the elements be prioritized?
- How do we implement the vision?

In response, one written comment letter was received from David Olsen, Director of the Center for Energy Efficiency and Renewable Technologies. As Mr. Olsen discussed in his oral comments made at the workshop (see Section 2), his written comments were a report on work underway in the Rocky Mountain Area Transmission Study (RMATS) on Options for Optimizing Use of Existing Transmission Assets as an Alternative to New Construction. The tariff and operational mechanisms discussed in RMATS, which allow for fuller use of existing transmission, may be of particular interest in California, especially considering the acceleration of renewable energy goals contemplated by the *Energy Action Plan*.